INERGY L P
Form 10-K
November 16, 2011
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

**(Mark One)**

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the fiscal year ended September 30, 2011**

**OR**

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the transition period from to .**

**Commission file number: 000-32453**

# INERGY, L.P.

**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **43-1918951** |
| **(State or other jurisdiction of** | **(I.R.S. Employer** |

| | |
|---|---|
| incorporation or organization) | Identification No.) |

**Two Brush Creek Boulevard, Suite 200, Kansas City, Missouri 64112**

**(Address of principal executive offices) (Zip Code)**

**(816) 842-8181**

**(Registrant s telephone number including area code)**

**SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:**

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Units representing limited partnership interests | The New York Stock Exchange |

**SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT: None**

Indicate by check mark if registrant is a well-known seasoned issuer, as defined by Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

| | |
|---|---|
| Large accelerated filer x | Accelerated filer ¨ |
| Non-accelerated filer ¨ (Do not check if a smaller reporting company) | Smaller reporting company ¨ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the following documents are incorporated by reference into the indicated parts of this report: None.

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**GUIDE TO READING THIS REPORT**

The following information should help you understand some of the conventions used in this report.

Throughout this report,

(1) When we use the terms we, us, our, our company, Inergy, or Inergy, L.P., we are referring either to Inergy, L.P., the registrant itself, or to Inergy, L.P. and its operating subsidiaries collectively, as the context requires.

(2) When we use the term our predecessor, we are referring to Inergy Partners, LLC, the entity that conducted our business before our initial public offering, which closed on July 31, 2001. Inergy, L.P. was formed as a Delaware limited partnership on March 7, 2001 and did not have operations until the closing of our initial public offering. Our predecessor commenced operations in November 1996. The discussion of our business throughout this report relates to the business operations of Inergy Partners, LLC before Inergy, L.P. s initial public offering and of Inergy, L.P. thereafter.

(3) When we use the term Inergy Propane, we are referring to Inergy Propane, LLC itself, or to Inergy Propane, LLC and its operating subsidiaries collectively, as the context requires.

(4) When we use the term Inergy Midstream, we are referring to Inergy Midstream, LLC itself, or to Inergy Midstream, LLC and its operating subsidiaries collectively, as the context requires.

(5) When we use the term finance company, we are referring to Inergy Finance Corp., a subsidiary of Inergy, L.P., formed on September 21, 2004.

(6) When we use the term general partner, we are referring to Inergy GP, LLC.

(7) When we use the term Inergy Holdings or Holdings, we are referring to Inergy Holdings, L.P. itself, or to Inergy Holdings, L.P. and its subsidiaries collectively, as the context requires, prior to the Merger that took place on November 5, 2010.

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**INERGY, L.P.**

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# PART I

## Item 1. Business.

### Recent Developments

On August 9, 2011, we announced our intention to file a registration statement with the Securities and Exchange Commission ( SEC ) for the initial public offering ( IPO ) of a minority interest of a new master limited partnership formed to initially own and operate our Northeast natural gas and natural gas liquids ( NGL ) midstream storage and transportation business. We intend to use all cash proceeds received in the IPO to repay indebtedness.

Consistent with the foregoing announcement, on August 24, 2011, our wholly-owned subsidiary, Inergy Midstream filed a registration statement for the IPO. As part of the IPO, Inergy Midstream intends to convert from a Delaware limited liability company into a Delaware limited partnership, change its name to Inergy Midstream, L.P., and list its common units on the New York Stock Exchange ( NYSE ) under the symbol NRGM .

Upon completion of the IPO, Inergy Midstream expects to own and operate four natural gas storage facilities located in New York and Pennsylvania, a 1.5 million barrel NGL storage facility located near Bath, New York, and natural gas pipelines located in New York and Pennsylvania. Our remaining midstream assets after the IPO are expected to include our West Coast NGL business, our Tres Palacios natural gas storage facility and our salt production business ( US Salt ). We expect to complete the IPO in December 2011; however, there can be no assurance that the IPO will be completed this year, if at all, on the terms described above or otherwise.

### General

Inergy, L.P., a publicly traded Delaware limited partnership, was formed on March 7, 2001 and we closed on our initial public offering on July 31, 2001. We own and operate a growing, geographically diverse retail and wholesale propane supply, marketing and distribution business. We also own and operate a growing midstream business with natural gas storage and transportation operations, NGL processing, fractionation, storage and marketing operations, and salt production operations.

We believe we are the fourth largest propane retailer in the United States based on retail propane gallons sold. For the fiscal year ended September 30, 2011, we sold and physically delivered 325.6 million gallons of propane to retail customers and 422.8 million gallons of propane to wholesale customers. Our propane business includes the retail marketing, sale and distribution of propane, including the sale and lease of propane supplies and equipment, to residential, commercial, industrial and agricultural customers. We market our propane products under various regional brand names. As of October 31, 2011, we serve retail customers in 33 states from 338 customer service centers, which have an aggregate of 34.6 million gallons of above-ground propane storage. In addition to our retail propane business, we operate a wholesale supply, marketing and distribution business, providing propane procurement, transportation and supply and price risk management services to our customer service centers, as well as to independent dealers, multistate marketers, petrochemical companies, refinery and gas processors and a number of other NGL marketing and distribution companies in 41 states, primarily in the Midwest, Northeast and South.

We believe we are the largest independent natural gas storage provider in the United States based on the total working gas capacity of our storage facilities. Our natural gas storage facilities include:

- Stagecoach, a multi-cycle natural gas storage facility located in Tioga County, New York and Bradford County, Pennsylvania with 26.25 Bcf of certificated working gas capacity. Located approximately 150 miles northwest of New York City, the facility is the closest natural gas storage facility to the northeastern demand market. The Stagecoach facility generates fee-based revenues and is currently 95% contracted primarily with investment grade customers with term contracts having a weighted-average maturity extending to 2015;

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Thomas Corners, a multi-cycle natural gas storage facility located in Steuben County, New York with 7.0 Bcf of certificated working gas capacity. The facility generates fee-based revenues and is currently 100% contracted primarily with investment grade customers with term contracts having a weighted-average maturity extending to 2015;

Steuben, a single-turn natural gas storage facility located in Schuyler County, New York with 6.2 Bcf of certificated working gas capacity. The facility generates fee-based revenues and is currently 100% contracted primarily with investment grade customers with term contracts having a weighted-average maturity extending to 2013;

Tres Palacios, a multi-cycle salt dome natural gas storage facility located in Matagorda and Wharton Counties, Texas with approximately 38.4 Bcf of certificated working gas capacity. Located approximately 100 miles southwest of Houston, the facility is potentially expandable by up to an additional 9.5 Bcf of working gas capacity. We have placed three caverns into commercial service and expect to place a fourth cavern into service in 2015. The Tres Palacios facility generates fee-based revenues and is currently 71% contracted (on a firm and interruptible basis). Our firm contracts have a weighted-average maturity date extending to 2013. Our contractual customers include investment grade rated companies as well as companies that have posted collateral in accordance with the terms of our Federal Energy Regulatory Commission ( FERC ) certificate. We acquired the Tres Palacios facility on October 14, 2010; and

Seneca Lake, a multi-cycle natural gas storage facility in Schuyler County, New York with 1.45 Bcf of certificated working gas capacity. The facility generates fee-based revenues and is currently 59% contracted with primarily investment grade customers with term contracts having a weighted-average maturity extending to 2018. We acquired the Seneca Lake facility on July 13, 2011.

In addition to our natural gas storage facilities, our midstream business primarily includes:

natural gas transportation assets, including the 37.5 mile Inergy East intrastate pipeline located in New York and the Stagecoach pipeline laterals and added compression and related facilities (collectively our North/South Project), which when completed will provide 325 MMcf/d of firm transportation wheeling services to our North/South shippers. Our transportation assets generate fee-based revenues and are currently 100% contracted with investment grade customers with term contracts having a weighted-average maturity extending to 2021 for Inergy East intrastate pipeline and 2016 for the Stagecoach North/South Project;

a West Coast NGL business located near Bakersfield, California, which includes a 24.0 million gallon NGL storage facility, a 25.0 MMcf/day natural gas processing plant, a 12,000 barrels per day NGL fractionation plant, an 8,000 barrels per day butane isomerization plant, NGL rail and truck terminals, and NGL transportation and marketing operations;

the Bath NGL storage facility, a 1.5 million barrel salt cavern propane and butane storage facility located near Bath, New York. Located approximately 210 miles northwest of New York City, the facility generates fee-based revenues and is currently 100% subleased to primarily investment grade customers with term contracts having a weighted-average maturity extending to 2012; and

US Salt, an industry-leading solution mining and salt production company located in Schuyler County, New York. US Salt produces and sells over 300,000 tons of salt each year. The solution mining process used by US Salt creates salt caverns that can be developed into usable natural gas and NGL storage capacity.

We have grown primarily through acquisitions and, to a lesser extent, organic expansion projects. Since the inception of our predecessor in November 1996, we have acquired 90 companies through September 30, 2011, including 82 retail propane companies and 8 midstream businesses, for an aggregate purchase price of approximately $2.9 billion, including working capital, assumed liabilities and acquisition costs. In fiscal 2011, we acquired the Tres Palacios and Seneca Lake natural gas storage facilities, the Inergy East intrastate pipeline, and the assets of two propane companies for an aggregate purchase price, net of cash acquired, of $824.2 million.

The following chart sets forth information about each business we acquired during the fiscal year ended September 30, 2011, and through the date of this filing:

| Acquisition Date | Company | Location |
|---|---|---|
| October 2010 | Tres Palacios Gas Storage LLC | Matagorda County, TX |
| October 2010 | Schenck Gas Services, LLC | East Hampton, NY |
| November 2010 | Pennington Energy Corporation | Morenci, MI |
| July 2011 | Seneca Lake natural gas storage facility | Schuyler County, NY |
| July 2011 | Inergy East intrastate pipeline | Multiple counties in NY |

The address of our principal executive offices is Two Brush Creek Boulevard, Suite 200, Kansas City, Missouri, 64112 and our telephone number at this location is 816-842-8181. Our common units trade on the NYSE under the symbol NRGY . We electronically file certain documents with the SEC. We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K (as appropriate), along with any related amendments and supplements. From time-to-time, we also may file registration and related statements pertaining to equity or debt offerings. You may read and download our SEC filings over the internet from several commercial document retrieval services as well as at the SEC s website at www.sec.gov. You may also read and copy our SEC filings at the SEC s public reference room located at 100 F. Street, N.E., Washington, D.C. 20549. Please call the SEC 1-800-SEC-0330 for further information concerning the public reference room and any applicable copy charges. In addition, our SEC filings are available at no cost after the filing thereof on our website at www.inergylp.com. Please note that any internet addresses provided in this Form 10-K are for information purposes only and are not intended to be hyperlinks. Accordingly, no information found and/or provided at such internet addresses is intended or deemed to be incorporated by reference herein.

**Industry Background and Competition**

**Propane**

Propane, a by-product of natural gas processing and petroleum refining, is a clean-burning energy source recognized for its transportability and ease of use relative to alternative stand-alone energy sources. Our retail propane business consists principally of transporting propane to our customer service centers and other distribution areas and then to tanks located on our customers premises. Retail propane falls into four broad categories: residential, industrial, commercial and agricultural. Residential customers use propane primarily for space and water heating. Industrial customers use propane primarily as fuel for forklifts and stationary engines, to fire furnaces, as a cutting gas, in mining operations and in other process applications. Commercial customers, such as restaurants, motels, laundries and commercial buildings, use propane in a variety of applications, including cooking, heating and drying. In the agricultural market, propane is primarily used for tobacco curing, crop drying, poultry brooding and weed control.

Propane is extracted from natural gas or oil wellhead gas at processing plants or separated from crude oil during the refining process. Propane is normally transported and stored in a liquid state under moderate pressure or refrigeration for ease of handling in shipping and distribution. When the pressure is released or the temperature is increased, it is usable as a flammable gas. Propane is colorless and odorless; an odorant is added to allow its detection. Propane is clean-burning, producing negligible amounts of pollutants when consumed.

The retail market for propane is seasonal because it is used primarily for heating in residential and commercial buildings. Approximately 70% of our retail propane volume is sold during the peak heating season from October through March. Consequently, sales and operating profits are generated mostly in the first and fourth calendar quarters of each calendar year.

Propane competes primarily with natural gas, electricity and fuel oil as an energy source, principally on the basis of price, availability and portability. Propane is more expensive than natural gas on an equivalent BTU basis in locations served by natural gas, but serves as an alternative to natural gas in rural and suburban areas where natural gas is unavailable or portability of product is required. Historically, the expansion of natural gas into traditional propane markets has been inhibited by the capital costs required to expand pipeline and retail distribution systems. Although the extension of natural gas pipelines tends to displace propane distribution in areas affected, we believe that new opportunities for propane sales can arise as more geographically remote neighborhoods are developed. Propane is traditionally less expensive to use than electricity for space heating, water heating, clothes drying and cooking. Although propane is similar to fuel oil in certain applications and market demand, propane and fuel oil compete to a lesser extent than propane and natural gas, primarily because of the cost of converting to fuel oil. The costs associated with switching from appliances that use fuel oil to appliances that use propane are a significant barrier to switching. By contrast, natural gas can generally be substituted for propane in appliances designed to use propane as a principal fuel source.

In addition to competing with alternative energy sources, we compete with other companies engaged in the retail propane distribution business. Competition in the propane industry is highly fragmented and generally occurs on a local basis with other large full-service, multi-state propane marketers, smaller local independent marketers and farm cooperatives. Based on industry publications, we believe that the 10 largest retailers account for 39% of the total retail sales of propane in the United States and that no single marketer has a greater than 10% share of the total retail market in the United States. Most of our customer service centers compete with several marketers or distributors. Each customer service center operates in its own competitive environment because retail marketers tend to locate in close proximity to customers. Our typical customer service center generally has an effective marketing radius of approximately 25 miles, although in certain rural areas the marketing radius may be extended by a satellite location.

The ability to compete effectively further depends on the reliability of service, responsiveness to customers and the ability to maintain competitive prices. We believe that our safety programs, policies and procedures are more comprehensive than many of our smaller, independent competitors and give us a competitive advantage over such retailers. We also believe that our service capabilities and customer responsiveness differentiate us from many of these smaller competitors. Our employees are on call 24-hours and seven-days-a-week for emergency repairs and deliveries.

Retail propane distributors typically price retail usage based on a per gallon margin over wholesale costs. As a result, distributors generally seek to maintain their operating margins by passing costs through to customers, thus insulating themselves from volatility in wholesale propane prices.

The propane distribution industry is characterized by a large number of relatively small, independently owned and locally operated distributors. Each year, a number of these local distributors have sought to sell their business for reasons that include, among others, retirement and estate planning. In addition, the propane industry faces increasing environmental regulations and escalating capital requirements needed to acquire advanced, customer-oriented technologies. Primarily as a result of these factors, the industry is undergoing consolidation and we, as well as other national and regional distributors, have been active consolidators in the propane market. In recent years, an active, competitive market has existed for the acquisition of propane assets and businesses. We expect this acquisition market to continue for the foreseeable future.

The wholesale propane business is highly competitive. Our competitors in the wholesale business include producers and independent regional wholesalers. We believe that our wholesale supply and distribution business provides us with a stronger regional presence and a reasonably secure, efficient supply base and positions us well for expansion through acquisitions.

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**Midstream**

The midstream sector of the natural gas industry provides the link between exploration and production and the delivery of natural gas and its components to end-use markets. The midstream sector consists generally of gathering and processing, transportation and storage activities. Our midstream operations focus on storage and transportation activities for both natural gas and NGLs, and additional processing and marketing services for NGLs.

*Natural Gas Storage*

The fundamentals of the natural gas market create a basic demand for storage. Natural gas is produced at a relatively steady rate throughout the year so natural gas supply is relatively constant. However, natural gas consumption is highly seasonal because the market consumes more natural gas in the winter than can be produced. In contrast, more natural gas is produced in the summer than is consumed, which creates this fundamental need for storage. Natural gas storage acts as the balancing mechanism between supply and demand.

Natural gas storage plays a vital role in maintaining the reliability of natural gas supplies needed to meet consumer demands. Storage facilities are used by pipelines to balance operations, by end users (such as power generation companies and location gas distribution companies) to manage volatility and secure natural gas supplies, and by independent natural gas marketing and trading companies in connection with the execution of their trading strategies. Storage allows for the warehousing of natural gas and is used to inject excess production during periods of low demand (typically, warmer summer months) and to withdraw natural gas during periods of high demand (typically, colder winter months).

Natural gas is a significant component of energy consumption in the United States. According to the Energy Industry Administration ( EIA ), natural gas consumption accounted for approximately 24% of all energy used in the United States in 2010, representing 24 Tcf of natural gas. The EIA estimates that over the next 27 years, total domestic energy consumption will increase by over 15%, with natural gas consumption directly benefiting from population growth, growth in cleaner-burning natural gas-fired electric generation and natural gas vehicles.

Domestic natural gas consumption is today satisfied primarily by production from conventional onshore and offshore production in the lower 48 states, as supplemented by production from historically declining pipeline imports from Canada, imports of liquefied natural gas ( LNG ) from foreign sources, and some Alaska production. In order to maintain current levels of U.S. natural gas supply and to meet the projected increase in demand, new sources of domestic natural gas must continue to be developed to offset an established trend of depletion associated with mature, conventional production as well as the uncertainty of future LNG imports and infrastructure challenges associated with sourcing additional production from Alaska. Over the past several years, a fundamental shift in production has emerged with the contribution of natural gas from unconventional resources (including shale formations) increasing from 6% of total U.S. natural gas supply in 2000 to 16% in 2008. The emergence of shale plays has resulted primarily from advances in horizontal drilling and hydraulic fracturing technologies, which have allowed producers to extract significant volumes of natural gas from these plays at cost-advantaged per unit economics versus most conventional plays. According to EIA forecasts, as the depletion of onshore conventional and offshore resources continues, natural gas from unconventional resource plays is forecast to fill the void and continue to gain market share from higher-cost sources of natural gas. In fact, the EIA estimates that natural gas production from the major shale formations is forecast to provide the majority of the growth in unconventional natural gas supply, increasing to approximately 47% of total U.S. natural gas supply in 2035 as compared with 16% in 2009.

Natural gas storage operators compete for customers based on geographical location, which determines connectivity to pipelines and proximity to supply sources and end-users, as well as operating reliability and flexibility, price, available capacity and service offerings. From an operator s perspective, having a diverse customer group that requires a variety of storage services is important to maximizing asset utilization and capturing incremental revenue opportunities while minimizing costs.

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The value of natural gas storage is a reflection of its critical role in providing the North American natural gas market with a degree of supply reliability, flexibility and demand balancing. The principal value drivers include location, volatility of natural gas prices, operating flexibility, seasonal spreads, and service reliability. Although competition within the industry is robust, there are significant barriers to entering the natural gas storage business. These barriers include, among others:

- *Costs and Execution Risk*. The costs of developing and constructing an underground storage facility are significant and highly variable, depending on drilling costs, subsurface issues, raw water availability, brine disposal arrangements, compression requirements, costs of establishing interconnects and other factors. The creation of storage facilities also involves significant execution risk with respect to drilling and completing wells and related sub-surface activities.

- *Time Commitment*. The length of time required to permit and develop a new project and place it into service can be long and unpredictable, generally ranging from two to four years or more, depending on the type of facility, location, permitting issues, subsurface issues and other factors.

- *Financing*. The magnitude and uncertainty of capital costs, length of the permitting and development cycle and scheduling uncertainties associated with natural gas storage development can present significant project financing challenges.

- *Limited Number of Sites*. Finding and developing new natural gas storage facilities, or acquiring existing facilities, is extremely competitive given that there are a limited number of sites that possess the requisite characteristics in terms of proximity to pipelines and load centers, operational flexibility, geological characteristics and overall risk/return profile.

- *Required Expertise*. Specialized expertise is required to identify market areas that require or will support additional storage capacity. In addition, acquiring, developing and operating natural gas storage facilities involves identifying, assessing and managing significant geological and other risks that require specialized industry knowledge and experience. Individuals with significant relationships with customers and other participants across the natural gas supply chain are also invaluable in providing a commercial understanding of the natural gas market.

The long-term demand for domestic storage services is driven primarily by the long-term demand for natural gas and the overall lack of balance between the supply of and demand for natural gas on a seasonal, monthly, daily or other basis. In general, to the extent the overall demand for natural gas increases and such growth includes higher demand from seasonal or weather-sensitive end-users, demand for natural gas storage services should also grow. In addition, any factors that contribute to more frequent and severe imbalances between the supply of and demand for natural gas, whether caused by supply or demand fluctuations, should increase the need for and value of storage services.

*NGL Business*

In general, natural gas produced at the wellhead contains various NGLs along with methane. This raw natural gas is usually not acceptable for transportation in the nation s major natural gas pipeline grid or for commercial use as a fuel. Our West Coast NGL business separates NGLs from methane, delivers methane to the local natural gas pipelines, and retains NGLs for further processing within our fractionation facility.

NGL fractionation facilities separate mixed NGL streams into discrete products: propane, normal butane, isobutane and pentanes (sometimes referred to as natural gasoline). The three primary sources of mixed NGLs fractionated in the United States are domestic natural gas processing plants, domestic crude oil refineries, and imports of butane and propane mixtures.

The purity NGL products (propane, normal butane, isobutane and natural gasoline) are typically used as raw materials by the petrochemical industry, feedstocks by refiners in the production of motor gasoline and by

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industrial and residential users as fuel. Propane is used both as a petrochemical feedstock in the production of propylene and as a heating, engine and industrial fuel. Normal butane is used as a petrochemical feedstock in the production of butadiene (a key ingredient of synthetic rubber), as a blendstock for motor gasoline and to derive isobutane through isomerization. Some more common uses of isobutane is blendstock in motor gasoline to enhance the octane content and in the production of propylene oxide. Natural gasoline, a mixture of pentanes and heavier hydrocarbons, is primarily used as a blendstock for motor gasoline, denaturant for ethanol and dilute for heavy crude oil.

The mixed NGLs delivered from domestic natural gas processing plants and crude oil refineries to our NGL fractionation facility are typically transported by NGL pipelines, railcars and transport trucks. Our West Coast NGL business also provides butane isomerization and refrigerated storage services. Our recently constructed isomerization facility chemically changes normal butane to isobutane, which we provide to area refineries for motor fuel blending. In addition, we store propane and butane at our Bath storage facility in New York.

Our NGL business encounters competition from fully integrated oil companies and independent NGL market participants. Each of our competitors has varying levels of financial and personnel resources and competition generally revolves around price, service and location. The majority of our NGL processing and fractionation activities are processing mixed NGL streams for third-party customers and to support our NGL marketing activities under contractual and fee-based arrangements. These fees (typically in cents per gallon) are subject to adjustment for changes in certain fractionation expenses, including natural gas fuel costs. Our integrated midstream energy asset system affords us flexibility in meeting our customers needs. While many companies participate in the natural gas processing business, few have a presence in significant downstream activities such as NGL fractionation and transportation and NGL marketing as we do. Our competitive position and presence in these downstream businesses allow us to extract incremental value while offering our customers enhanced services, including comprehensive service packages.

We believe that current industry dynamics are resulting in increases in domestic drilling targeting NGLs, particularly in areas with unconventional reserves, creating the need for additional NGL infrastructure and services. Factors contributing to this include (i) a strong crude oil and NGL price environment relative to current natural gas prices, with the price of West Texas Intermediate crude oil at $79.20/bbl, Henry Hub spot prices for natural gas at $3.73/MMBTU and composite NGL prices at $1.42/gallon as of September 30, 2011; (ii) the continuation of oil and natural gas exploration and production innovation including geophysical interpretation, horizontal drilling and well completion techniques; (iii) a trend toward increased drilling in oil, condensate and NGL rich, or liquids rich reservoirs, especially resource plays; and (iv) increasing levels of supply of mixed NGLs coupled with strong demand from petrochemical complexes and exports, which are leading to higher capacity utilization of NGL storage facilities. We believe these trends will continue to result in strong demand for the services provided by our NGL businesses.

*Salt Production*

According to the Salt Institute, a North American based non-profit salt industry trade association, more than 250 million metric tons of salt were produced in the world in 2008. Salt is generally categorized into four types based upon the method of production: evaporated salt, solar salt, rock salt and salt in brine. Dry salt is produced through the following methods: solution mining and mechanical evaporation, solar evaporation or deep-shaft mining. Our US Salt facility, located in Schuyler County, New York, produces salt using solution mining and mechanical evaporation. The facility produces and sells over 300,000 tons of salt each year.

In solution mining, wells are drilled into salt beds or domes and then water is injected into the formation and circulated to dissolve the salt. The salt solution, or brine, is then pumped out and taken to a plant for evaporation. At the plant, the brine is treated to remove minerals and pumped into vacuum pans, sealed containers in which the brine is boiled and then evaporated until the salt is left behind. Then it is dried and refined. Depending on the type of salt to be produced, iodine and an anti-clumping agent may be added to the salt. Most food grade table salt is produced in this manner.

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After the salt is removed from a solution-mined salt deposit, the empty cavern can be used to store other substances, such as natural gas, NGLs and compressed air. Each new brine well that US Salt drills creates additional potential storage capacity for us.

We believe that existing cavern capacity created by US Salt s solution mining can be converted into up to 5 million barrels of NGL storage. We are currently working to convert a portion of this capacity into a 2.1 million gallon propane and butane storage facility near Watkins Glen, New York. We have also identified certain caverns for potential development into up to 10 Bcf of natural gas storage capacity, which we currently expect to place into service by 2014.

**Business Strategy**

Our primary objective is to increase distributable cash flow for our unitholders, while maintaining the highest level of commitment and service to our customers. We have engaged and will continue to engage in objectives of further growth through acquisitions both in our propane and midstream operations, internally generated expansion and measures aimed at increasing the profitability of existing operations.

**Competitive Strengths**

We intend to pursue this objective by capitalizing on what we believe are our competitive strengths as follows:

*Proven Acquisition Expertise*

Since our predecessor s inception and through September 30, 2011, we have acquired and successfully integrated 90 companies 82 retail propane companies and 8 midstream businesses. Our executive officers and key employees, who together average more than 15 years experience in the propane and midstream energy-related industries, have developed commercial relationships with business owners and industry participants throughout the United States. These significant industry contacts have enabled us to negotiate most of our acquisitions on an exclusive basis. We believe that this acquisition expertise should allow us to continue to grow through strategic and accretive acquisitions. Our acquisition program will continue to seek:

- businesses that generate distributable cash flow that is accretive to common unitholders on a per unit basis;
- businesses in attractive market areas;
- propane businesses with established names and reputations for customer service and reliability;
- propane businesses with high concentration of propane sales to residential customers;
- midstream businesses that generate predictable, stable fee-based cash flow streams;
- midstream businesses with organic expansion opportunities or strategic regional enhancement; and
- retention of key employees in acquired businesses.

*Management Experience*

Our senior management team has extensive experience in the propane and midstream energy industry. Our management team has a proven track record of enhancing the value of our partnership, through the acquisition, integration and optimization of the businesses we own and operate. Our management team also has significant expertise developing and operating natural gas and NGL assets, as well as significant relationships with participants across the energy supply chain.

*Flexible Financial Structure*

We have a $1.0 billion credit agreement, under which we have $700 million of revolving loan capacity. We believe the funds available under the credit agreement, combined with our ability to fund acquisitions and organic growth projects through the issuance of additional partnership interests, provide us with a flexible financial structure that will facilitate our acquisition and organic growth plans. We expect that the elimination of our incentive distribution rights in November 2010 will, over time, reduce our cost of capital and, in turn, enhance our ability to compete for future acquisitions and more effectively finance organic growth projects.

**Propane Business Strengths**

*Focus on High Percentage of Retail Sales to Residential Customers*

Our retail propane operations concentrate on sales to residential customers. Residential customers tend to generate higher margins and are generally more stable purchasers than other customers. For the fiscal year ended September 30, 2011, sales to residential customers represented approximately 67% of our retail propane gallons sold. Although overall demand for propane is affected by weather and other factors, we believe that residential propane consumption is not materially affected by general economic conditions because most residential customers consider home space heating to be an essential purchase. In addition, we own nearly 90% of the propane tanks located at our customers homes. In many states, fire safety regulations restrict the refilling of a leased tank solely to the propane supplier that owns the tank. These regulations, which require customers to switch propane tanks when they switch suppliers, help enhance the stability of our customer base because of the inconvenience and costs involved with switching tanks and suppliers.

*Regionally Branded Operating Structure*

We believe that our success in maintaining customer stability and our low cost operating structure at our customer service centers results from our decentralized operation under established, locally recognized trade names. We attempt to capitalize on the reputation of the companies we acquire by retaining their local brand names and employees, thereby preserving the goodwill of the acquired business and fostering employee loyalty and customer retention. We expect our local branch management to continue to manage the marketing programs, new business development, customer service and customer billing and collections. We believe that our employee incentive programs encourage efficiency and allow us to control costs at the corporate and field levels.

*Operations in Attractive Propane Markets*

A majority of our propane operations are concentrated in attractive propane market areas, where natural gas distribution is not cost-effective, margins are relatively stable and tank control is relatively high. We intend to pursue acquisitions in similar attractive markets.

*Comprehensive Propane Logistics and Distribution Business*

One of our distinguishing strengths is our propane procurement and distribution expertise and capabilities. For the fiscal year ended September 30, 2011, we delivered 422.8 million gallons of propane on a wholesale basis to our various customers. These operations are significantly larger on a relative basis than the wholesale operations of most publicly-traded propane businesses. We also provide transportation services to these distributors through our fleet of transport vehicles, and price risk management services to our customers through a variety of financial and other instruments. The presence of our trucks serving our wholesale customers allows us to take advantage of various pricing and distribution inefficiencies that exist in the market from time to time. We believe our wholesale business enables us to obtain valuable market intelligence and awareness of potential acquisition opportunities. Because we sell on a wholesale basis to many residential and commercial retailers, we have an ongoing relationship with a large number of businesses that may be attractive acquisition opportunities for us. We believe that we will have an adequate supply of propane to support our growing retail operations at prices that are generally available only to large wholesale purchasers. This purchasing scale and resulting expertise also helps us avoid shortages during periods of tight supply to an extent not generally available to other retail propane distributors.

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**Midstream Business Strengths**

*Strategically Located Assets*

Our assets are situated close to or within demand-based market areas, which positions us well to leverage the services we offer to our customers relative to our competitors.

In the Northeast, our natural gas and NGL storage facilities are strategically located in and around the Marcellus shale and within approximately 200 miles of the New York City metropolitan market. Our natural gas storage facilities are among the closest storage facilities to the New York City market and have the capability of delivering gas to this high-demand market and other Northeast and Mid-Atlantic market centers. We believe that our pipeline connectivity to major U.S. and Canadian natural gas supply sources provides us with a distinct competitive advantage, and that the strategic location of our assets and a lack of viable storage substitutes in the region drive the high utilization of our facilities. Moreover, the location of US Salt s properties relative to our existing storage operations provides greater opportunities to grow organically and further harness our competitive advantage in the Northeast.

Our Tres Palacios facility is strategically located near shale gas supply (including the Eagle Ford shale), connected to multiple supply sources and supports strong demand markets. The storage facility, which is located within approximately 100 miles of Houston, provides us access to the Houston and San Antonio metropolitan areas and the broader Texas markets, as well as markets in the Northeast, Midwest, Southeast, Florida and Mid-Atlantic United States and Mexico. The Texas natural gas fired electric generation market is among the largest in the United States. In addition, our West Coast NGL business is strategically located between the major refining centers of Los Angeles and San Francisco.

We believe there are opportunities to further leverage our geographic location, expand our current asset base and to enhance the platform of services we offer to our customers that will further enhance the value and profitability of these assets.

*Inventory of Internal Growth Projects*

We are developing numerous growth projects around our existing Northeast natural gas and NGL assets designed to enhance our profitability and increase our operating scale. As further described in Midstream Operations later in Item I, our significant Northeast growth projects include:

- Natural Gas Transportation. We expect our proposed MARC I pipeline, which we anticipate placing into service in mid-year 2012, and our North/South II expansion project, which we announced in September 2011, to add significant incremental transportation capability and fee-based revenue to our natural gas transportation business.

- Natural Gas Storage. We expect to expand our Seneca Lake facility by approximately 0.6 Bcf by December 2012, and to convert existing cavern capacity on US Salt properties into approximately 10.0 Bcf of natural gas storage capacity by 2014.

- NGL Storage. We are developing a 2.1 million barrel propane and butane storage facility near Watkins Glen, New York, using existing cavern capacity created by US Salt s solution-mining process. We expect to place into service the Watkins Glen NGL storage development project by June 2012.

We are also focused on growth opportunities at our Tres Palacios storage facility in Texas. In 2011, we secured the right to store NGLs in certain caverns developed for our Tres Palacios facility and elsewhere on the Markham salt dome in Texas. We expect to utilize our NGL storage rights over the next few years as greater volumes of NGLS are produced from the Eagle Ford shale and other plays in and around Texas. We also expect to interconnect Tres Palacios to additional interstate or intrastate pipelines in order to improve connectivity and offer greater storage and transportation services to our customers. For example, we anticipate extending the Tres Palacios header system by approximately 20 miles to connect with Copano s Houston Central gas processing

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plant in Colorado County, Texas, which would allow shippers to move gas along 60 miles of header pipe with access to a combination of 10 interstate and intrastate pipelines and the Tres Palacios storage facility. In addition, we currently expect to place a fourth cavern into natural gas (or, depending on market demand, NGL) storage service in 2015 after the cavern is converted from brine production into natural gas or NGL storage service.

We anticipate that these projects will allow us to better serve our customers storage and transportation needs, increase margins and enhance our ability to obtain contracts for the use of our assets. We believe these projects will be accretive to our common unitholders and increase the scale and stability of our business.

**Operations**

Our operations reflect our two reportable segments: propane operations and midstream operations.

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**Propane Operations**

*Retail Propane*

*Customer Service Centers*

At October 31, 2011, we distributed propane to retail customers from 338 customer service centers in 33 states. We market propane primarily in rural areas, but also have a significant number of customers in suburban areas where energy alternatives to propane such as natural gas are generally not available. We market our propane primarily in the eastern half of the United States through our customer service centers using multiple regional brand names. The following table shows our customer service centers by state:

| State | Number of Customer Service Centers |
|---|---|
| Alabama | 38 |
| Arizona | 1 |
| Arkansas | 2 |
| Colorado | 5 |
| Connecticut | 4 |
| Delaware | 1 |
| Florida | 19 |
| Georgia | 4 |
| Illinois | 4 |
| Indiana | 21 |
| Kentucky | 2 |
| Maine | 5 |
| Maryland | 6 |
| Massachusetts | 7 |
| Michigan | 34 |
| Mississippi | 25 |
| New Hampshire | 3 |
| New Jersey | 7 |
| New Mexico | 3 |
| New York | 10 |
| North Carolina | 26 |
| Ohio | 25 |
| Oklahoma | 3 |
| Pennsylvania | 17 |
| Rhode Island | 1 |
| South Carolina | 4 |
| Tennessee | 9 |
| Texas | 26 |
| Vermont | 10 |
| Virginia | 5 |
| Washington | 3 |
| West Virginia | 2 |
| Wisconsin | 6 |
| Total | 338 |

From our customer service centers, we also sell, install and service equipment related to our propane distribution business, including heating and cooking appliances. Typical customer service centers consist of an office and

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service facilities, with one or more 12,000 to 30,000 gallon bulk storage tanks. Some of our customer service centers also have an appliance showroom. We have several satellite facilities that typically contain only large capacity storage tanks.

*Customer Deliveries*

Retail deliveries of propane are usually made to customers by means of our fleet of bobtail and rack trucks. Propane is pumped from the bobtail truck, which generally holds 2,500 to 3,000 gallons, into a stationary storage tank at the customer s premises. The capacity of these tanks range from 100 gallons to 1,200 gallons, with a typical tank having a capacity of 100 to 300 gallons in milder climates and 500 to 1,000 gallons in colder climates. We also deliver propane to retail customers in portable cylinders, which typically have a capacity of five to thirty-five gallons. These cylinders typically are picked up by us and replenished at our distribution locations, then returned to the retail customer. To a limited extent, we also deliver propane to certain customers in larger trucks known as transports, which have an average capacity of 10,000 gallons. These customers include industrial customers, large-scale heating accounts and large agricultural accounts.

During the fiscal year ended September 30, 2011, we delivered approximately 44% of our propane volume to retail customers and 56% to wholesale customers. Our retail volume sold to residential, industrial and commercial and agricultural customers were as follows:

- 67% to residential customers;
- 26% to industrial and commercial customers; and
- 7% to agricultural customers.

No single retail customer accounted for more than 1% of our revenue during the fiscal year ended September 30, 2011.

Approximately half of our residential customers receive their propane supply under an automatic delivery program. Under the automatic delivery program, we deliver propane to our heating customers approximately six times during the year. We determine the amount of propane delivered based on weather conditions and historical consumption patterns. Our automatic delivery program eliminates the customer s need to make an affirmative purchase decision, promotes customer retention by ensuring an uninterrupted supply and enables us to efficiently route deliveries on a regular basis. We promote this program by offering level payment billing, discounts, fixed price options and price caps. In addition, we generally provide emergency service 24 hours a day, seven days a week, 52 weeks a year.

*Seasonality*

The retail propane business is seasonal with weather conditions significantly affecting demand for propane. We believe that the geographic diversity of our areas of operations helps to minimize our exposure to regional weather. Although overall demand for propane is affected by climate, changes in price and other factors, we believe our residential and commercial business to be relatively stable due to the following characteristics:

- residential and commercial demand for propane has not been significantly affected by general economic conditions due to the largely non-discretionary nature of most propane purchases by our customers;
- loss of customers to competing energy sources has been low;
- the tendency of our customers to remain with us due to the product being delivered pursuant to a regular delivery schedule and to our ownership of approximately 90% of the storage tanks utilized by our customers; and

our ability to offset customer losses through a combination of acquisitions and to a lesser extent, sales to new customers in existing markets.

Since home heating usage is the most sensitive to temperature, residential customers account for the greatest usage variation due to weather. Variations in the weather in one or more regions in which we operate can significantly affect the total volumes of propane we sell and the margins we realize and, consequently, our results of operations. We believe that sales to the commercial and industrial markets, while affected by economic patterns, are not as sensitive to variations in weather conditions as sales to residential and agricultural markets.

*Transportation Assets and Truck Maintenance*

Our transportation assets are operated by L&L Transportation, LLC, a wholly-owned subsidiary of Inergy Propane. The transportation of propane requires specialized equipment. Propane trucks carry specialized steel tanks that maintain the propane in a liquefied state. As of September 30, 2011, we owned a fleet of 145 tractors, 234 transports, 1,281 bobtail and rack trucks and 797 other service vehicles. In addition to supporting our retail and wholesale propane operations, our fleet is also used to deliver butane and ammonia for third parties and to distribute natural gas for various processors and refiners.

We own truck maintenance facilities located in Indiana, Ohio and Mississippi. We also have a trucking operation located in California as part of our NGL business. We believe that our ability to maintain the trucks we use in our propane operations significantly reduces the costs we would otherwise incur with third parties in maintaining our fleet of trucks.

*Pricing Policy*

Our pricing policy is an essential element in our successful marketing of propane. We base our pricing decisions on, among other things, prevailing supply costs, local market conditions and local management input. We rely on our regional management to set prices based on these factors. Our local managers are advised regularly of any changes in the posted prices of our propane suppliers. We believe our propane pricing methods allow us to respond to changes in supply costs in a manner that protects our customer base and gross margins. In some cases, however, our ability to respond quickly to cost increases could cause our retail prices to rise more rapidly than those of our competitors, possibly resulting in a loss of customers.

*Billing and Collection Procedures*

We retain our customer billing and account collection responsibilities at the local level. We believe that this decentralized approach is beneficial for a number of reasons:

- customers are billed on a timely basis;
- customers are more likely to pay a local business;
- cash payments are received faster; and
- local personnel have current account information available to them at all times in order to answer customer inquiries.

*Trademarks and Trade Names*

We use a variety of trademarks and trade names which we own, including Inergy and Inergy Services. We believe that our strategy of retaining the names of the companies we acquire has maintained the local identification of such companies and has been important to the continued success of the acquired businesses. We regard our trademarks, trade names and other proprietary rights as valuable assets and believe that they have significant value in the marketing of our products.

*Wholesale Supply, Marketing and Distribution Operations*

We currently provide wholesale supply, marketing and distribution services to independent dealers, multi-state marketers, petrochemical companies, refinery and gas processors and a number of other NGL marketing and distribution companies, primarily in the Midwest and Southeast. While our wholesale supply, marketing and distribution operations accounted for 28% of total revenue, this business represented 5% of our gross profit during the fiscal year ended September 30, 2011.

*Marketing and Distribution*

Because of the size of our wholesale operations one of our distinguishing strengths is our procurement and distribution expertise and capabilities. This is partly the result of the unique background of our management team, which has significant experience in the procurement aspects of the propane business. We also offer transportation services to these distributors through our fleet of transport trucks and price risk management services to our customers through a variety of financial and other instruments. Our wholesale supply, marketing and distribution business provides us with an additional income stream as well as extensive market intelligence and acquisition opportunities. In addition, these operations provide us with more secure supplies and better pricing for our customer service centers. Moreover, the presence of our trucks across the Midwest and Southeast allows us to take advantage of various pricing and distribution inefficiencies that exist in the market from time to time.

*Supply*

We obtain a substantial majority of our propane from domestic suppliers, with our remaining propane requirements provided by Canadian suppliers. During the fiscal year ended September 30, 2011, a majority of our sales volume was purchased pursuant to contracts that have a term of one year or less; the balance of our sales volume was purchased on the spot market. The percentage of our contract purchases varies from year to year. Supply contracts generally provide for pricing in accordance with posted prices at the time of delivery or the current prices established at major storage points, and some contracts include a pricing formula that typically is based on such market prices. Some of these agreements provide maximum and minimum seasonal purchase guidelines.

One supplier, BP Amoco Corp., accounted for 14% of propane purchases during the past fiscal year. No other single supplier accounted for more than 10% of propane purchases in the current year.

Propane generally is transported from refineries, pipeline terminals, storage facilities and marine terminals to our approximate 700 bulk storage tank facilities. We accomplish this by using our transports and contracting with common carriers, owner-operators and railroad tank cars. Our customer service centers and satellite locations typically have one or more 12,000 to 30,000 gallon storage tanks, which are generally adequate to meet customer usage requirements for seven days during normal winter demand. Additionally, we lease underground storage facilities from third parties under annual lease agreements.

We engage in risk management activities in order to reduce the effect of price volatility on our product costs and to help ensure the availability of propane during periods of short supply. We are currently a party to propane forward and option contracts with various third parties to purchase and sell propane at fixed prices in the future. We monitor these activities through enforcement of our risk management policy.

**Midstream Operations**

*Natural Gas Storage Operations*

We own and operate five high-performance natural gas storage facilities located in New York, Pennsylvania and Texas that have an aggregate working gas storage capacity of 79.3 Bcf with high peak injection and withdrawal

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capabilities. Our natural gas storage facilities, all of which are regulated by FERC, have low maintenance costs, long useful lives and comparatively high injection and withdrawal (or cycling) capabilities. Our facilities include:

***Stagecoach***, a multi-cycle natural gas storage facility located approximately 150 miles northwest of New York City in Tioga County, New York and Bradford County, Pennsylvania. The facility, which generates fee-based revenues under a market-based rate structure, is the closest natural gas storage facility to the northeastern U.S. demand market. Stagecoach s 24-mile, 30-inch diameter south pipeline lateral connects the facility to Tennessee Gas Pipeline s ( TGP ) 300 Line, and its 10-mile, 20-inch diameter north pipeline lateral connects the facility to the Millennium Pipeline. The Stagecoach laterals diversify our supply sources and provide wheeling and other transportation opportunities to shippers. We acquired Stagecoach in 2005;

***Thomas Corners***, a multi-cycle natural gas storage facility located in Steuben County, New York. The facility generates fee-based revenues under a market-based rate structure. An 8-mile, 12-inch diameter pipeline lateral connects Thomas Corners to TGP s 400 Line, and a 7.5-mile, 8-inch diameter pipeline lateral connects the Thomas Corners to Millennium. We developed and placed Thomas Corners into service in November 2009;

***Steuben,*** a single-turn natural gas storage facility located in Steuben County, New York. The facility generates fee-based revenues under a cost-of-service rate structure. A 12.5 mile, 12-inch diameter pipeline lateral connects Steuben to Dominion, and a 6-inch diameter pipeline measuring less than one mile connects Steuben and our Thomas Corners facility. We acquired in October 2007 a minority interest in the owner/operator of the Steuben facility, and we increased our ownership interest to 100% in fiscal 2010;

***Tres Palacios***, a multi-cycle salt dome natural gas storage facility located in Matagorda County, Texas. The facility generates fee-based revenues under a market-based rate structure. Located approximately 100 miles southwest of Houston, Tres Palacios is currently connected to a total of ten intrastate and interstate pipelines offering connectivity to multiple demand markets including the Houston and San Antonio metropolitan areas, the broader Texas markets, and markets in the Northeast, Midwest, Southeast, Florida and Mid-Atlantic United States and Mexico. The Tres Palacios facility s header system consists of dual, bilateral 24-inch diameter pipelines, with a 31 mile north pipeline corridor in Matagorda and Wharton Counties, Texas and a 10.8 mile south pipeline corridor in Matagorda County, Texas. We acquired the facility s owner/operator, Tres Palacios Gas Storage LLC, on October 14, 2010; and

***Seneca Lake***, a multi-cycle natural gas storage facility located in Schuyler County, New York. The facility generates fee-based revenues under a market-based rate structure. Seneca Lake is connected to Dominion s system via the 20-mile, 16-inch diameter Seneca West pipeline lateral, and crosses both Millennium and the Empire Pipeline. We intend to interconnect Seneca Lake with Millennium under our existing blanket FERC authority by December 2011, which we expect to increase market demand for storage service at Seneca Lake. We acquired Seneca Lake from New York State Electric & Gas Corporation ( NYSEG ) on July 13, 2011.

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Additional information concerning our natural gas storage facilities, as of September 30, 2011, is provided below.

| Facility Name/ Location | Facility Type | Percentage Contractually Committed | Certificated Working Gas Storage Capacity (Bcf) | Maximum Injection Rate (MMcf/d) | Maximum Withdrawal Rate (MMcf/d) | Pipeline Connections |
|---|---|---|---|---|---|---|
| **Stagecoach** Tioga County, New York; Bradford County, Pennsylvania | High Performance, Multi-Cycle, Depleted Reservoir | 95% | 26.25 | 250 | 500 | TGP s 300 Line; Millennium[(1)] |
| **Thomas Corners** Steuben County, New York | High Performance, Multi-Cycle, Depleted Reservoir | 100%[(2)] | 7.0 | 70 | 140 | TGP s 400 Line; Millennium; Dominion[(3)] |
| **Seneca Lake** Schuyler County, New York | High Performance, Multi-Cycle, Bedded Salt Cavern | 59% | 1.45 | 72.5 | 145 | Dominion |
| **Tres Palacios** Matagorda County, Texas | High Performance, Multi-Cycle, Salt Dome Cavern | 71% | 38.4 | 2,500 | 1,000 | Multiple[(4)] |
| **Steuben** Steuben County, New York | Single-Turn, Depleted Reservoir | 100% | 6.2 | 30 | 60 | TGP s 400 Line; Millennium; Dominion[(5)] |
| Total | | | 79.3 | 2,922.5 | 1,845 | |

(1) We have requested FERC authorization to interconnect Stagecoach s south lateral to Transco s Leidy Line as part of our MARC I pipeline project.
(2) Thomas Corners currently has 5.7 Bcf of operationally-available capacity, all of which has been sold under firm storage contracts. Therefore, 100% of the facility s operationally-available capacity is committed.
(3) Thomas Corners is indirectly connected to Dominion through our Steuben facility.
(4) Tres Palacios is interconnected to Florida Gas Transmission Company, LLC, Kinder Morgan Tejas Pipeline, L.P., Houston Pipe Line Company, Central Texas Gathering System, Natural Gas Pipeline Company of America, Transcontinental Gas Pipe Line Corporation, TGP, Valero Natural Gas Pipe Line Company, Channel Pipeline Company, and Texas Eastern Transmission, L.P.
(5) Steuben is indirectly connected to TGP and Millennium through our Thomas Corners facility.

*Natural Gas Transportation Operations*

We own natural gas pipelines, including storage pipeline laterals, located in New York and Pennsylvania that provide shippers with 30 MMcf/d of intrastate transportation capacity and, upon completion of the North/South expansion project, will provide shippers with 325 MMcf/d of interstate transportation capacity.

Our North/South expansion project, expected to be completed in November 2011, involves the installation of additional compression facilities that increase throughput capacity on Stagecoach s north and south laterals. We

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are installing a 13,400 horsepower electric-powered centrifugal compressor near the interconnect between Stagecoach s north lateral and the Millennium Pipeline in Tioga, New York, and a 15,300 horsepower electric-powered compressor near the interconnect between Stagecoach s south lateral and TGP s 300 Line in Bradford County, Pennsylvania. Shippers can wheel gas bidirectionally on a firm basis from the Millennium to TGP s 300 Line, or from points in between. In connection with this project, we entered into binding five-year agreements with five shippers to provide up to 325 MMcf/d of firm wheeling capacity at negotiated rates between receipt and delivery points at the existing interconnects with Millennium and the 300 Line.

Our proposed MARC I pipeline is a 39-mile, 30-inch diameter bidirectional natural gas pipeline that will connect the Stagecoach south lateral and TGP s 300 Line in Bradford County, Pennsylvania, with Transco s Leidy Line in Lycoming County, Pennsylvania. The project involves the installation of a 16,360 horsepower gas-fired compression facility in the vicinity of the Transco interconnect, a 15,000 horsepower electric-powered compression facility at the proposed interconnect between the Stagecoach south lateral and TGP s 300 Line, and related metering, flow control and appurtenant facilities. We have entered into binding 10-year agreements with four shippers to provide approximately 550 MMcf/d of firm interstate transportation service on the MARC I pipeline after its completion. We requested FERC authorization for the project in August 2010 and currently expect to receive approval in November 2011. We expect to begin construction shortly following our receipt of FERC authorization, and we expect to complete and place into service the pipeline in July 2012.

On September 29, 2011, we announced a non-binding open season relating to the North/South II expansion project. The open season is designed to gauge shipper interest in transporting additional natural gas volumes bidirectionally on a firm basis through our existing Stagecoach laterals from Millennium to TGP s 300 Line, and all points in between. In connection with this project, we expect to lay approximately three miles of pipe to connect the Stagecoach north lateral with our Inergy East pipeline. This interconnection will allow shippers to transport volumes bidirectionally from TGP s 300 Line, and intermediate points including Millennium, to a new interconnect with Dominion in Tompkins County, New York, where our Inergy East pipeline interconnects with Dominion.

We also own and operate a 37.5-mile, 12-inch diameter intrastate pipeline that is located in New York and runs within approximately three miles of our Stagecoach north lateral s point of interconnection with the Millennium Pipeline. The Inergy East pipeline, formerly known as the Seneca Lake east lateral pipeline, is subject to regulation by the New York Public Service Commission ( NYPSC ). We provide 30 MMcf/d of firm transportation capacity to NYSEG under an agreement approved by the NYPSC to transport natural gas from our interconnect with Dominion s system to certain NYSEG city gates within its service territory. The initial term of the NYSEG contract is 10 years, and NYSEG has the right to extend the term for incremental five-year periods during the life of the pipeline. We acquired the intrastate pipeline from NYSEG in July 2011 as part of our acquisition of the Seneca Lake natural gas storage facility.

*NGL Storage Operations*

Our Bath NGL storage facility, acquired in October 2006, is a 1.7 million barrel salt cavern storage facility located near Bath, New York. The facility generates fee-based revenue and currently has 1.5 million barrels of storage capacity operationally available. We have contracted all of the operationally-available storage capacity primarily to strong, investment grade companies. The Bath facility is supported by both rail and truck terminals capable of loading and unloading 23 rail cars per day and 17 truck transports per day.

We are developing a 2.1 million barrel NGL storage facility near Watkins Glen, New York, using existing cavern capacity created by US Salt s solution-mining process. Propane and butane will be stored in these caverns seasonally. The facility will be supported by rail and truck terminal facilities capable of loading and unloading 32 railcars per day and 45 truck transports per day, and will connect with TEPPCO NGL s interstate pipeline. Upon receipt of New York State Department of Environmental Conservation ( NYSDEC ) approval, we believe the Watkins Glen facility can be expanded to 5.0 million barrels of storage capacity. We expect to receive NYSDEC approval in early 2012 to construct the Watkins Glen facility, and to place the project into service by June 2012. In connection with this project, we entered into a binding storage contract with an anchor customer for 2.0 million barrels of future propane and butane storage service.

*West Coast NGL Operations*

Our West Coast NGL business, acquired in 2003, is located near Bakersfield, California. The facility includes a 25.0 MMcf/day natural gas processing plant, a 12,000 bpd NGL fractionation plant, an 8,000 bpd butane isomerization plant, NGL rail and truck terminals, a 24.0 million gallon NGL storage facility and NGL transportation/marketing operations.

*Salt Operations*

Our US Salt production facility, acquired in August 2008, is located in Schuyler County, New York, and produces salt using solution mining and mechanical evaporation. The facility is strategically located in close proximity to our Seneca Lake natural gas storage facility and our Watkins Glen NGL storage development project. US Salt produces and sells over 300,000 tons of salt each year.

For more information on our reportable business segments, see Note 13 to our consolidated financial statements.

**Employees**

As of October 31, 2011, we had 2,865 full-time employees and 66 part-time employees. Of the 2,931 employees, 132 were general and administrative and 2,799 were operational. Of the operational employees, 251 were members of labor unions. We believe that our relationship with our employees is satisfactory.

**Government Regulation**

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the law in substantially all of the states in which we operate. In some states these laws are administered by state agencies, and in others they are administered on a county or municipal level. Regarding the transportation of propane, ammonia and butane by truck, we are subject to regulations promulgated under the Federal Motor Carrier Safety Act. These regulations cover the transportation of hazardous materials and are administered by the United States Department of Transportation ( DOT ). We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We maintain various permits that are necessary to operate some of our facilities, some of which may be material to our operations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane and the transportation of ammonia and butane are consistent with industry standards and are in compliance in all material respects with applicable laws and regulations.

We are also subject to stringent federal, state and local environmental, health and safety laws and environmental regulations governing our operations. These laws and regulations impose limitations on the discharge and emission of pollutants and establish standards for the handling of solid and hazardous wastes. Applicable laws include the Resource Conservation and Recovery Act, the Comprehensive Environmental Response, Compensation and Liability Act ( CERCLA ), the Clean Air Act, the Occupational Safety and Health Act, the Emergency Planning and Community Right to Know Act, the Clean Water Act and comparable state or local statutes. CERCLA, also known as the Superfund law, imposes joint and several liability without regard to fault or the legality of the original conduct on certain classes of persons that are considered to have contributed to the release or threatened release of a hazardous substance into the environment. While propane is not a hazardous substance within the meaning of CERCLA, other chemicals used in our operations may be classified as hazardous substances. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of remedial liabilities and the issuance of injunctions restricting or prohibiting our activities. We have not received any notices that we have violated these environmental laws and regulations in any material respect and we have not otherwise incurred any material liability or capital expenditure thereunder.

Future developments, such as stricter environmental, health or safety laws and regulations, or more stringent enforcement of existing requirements could affect our operations. We do not anticipate that our compliance with or liabilities under environmental, health and safety laws and regulations, including CERCLA, will require any material increase in our capital expenditures or otherwise have a material adverse effect on us. To the extent that any environmental liabilities, or environmental, health or safety laws, or regulations are made more stringent, there can be no assurance that our results of operations will not be materially and adversely affected.

For acquisitions that involve the purchase of real estate, we conduct due diligence investigations to assess whether any material or waste has been sold from, or stored on, or released or spilled from any of that real estate prior to its purchase. This due diligence includes questioning the seller, obtaining representations and warranties concerning the seller s compliance with environmental laws and performing site assessments. During these due diligence investigations, our employees, and, in certain cases, independent environmental consulting firms, review historical records and databases and conduct physical investigations of the property to look for evidence of contamination, compliance violations and the existence of underground storage tanks.

*Midstream*

Our midstream operations are subject to extensive federal, state and local regulation. In particular, our natural gas storage and transportation facilities are subject to regulation by the FERC, and our natural gas pipelines (including storage lateral pipelines) are subject to regulation by the DOT s Pipeline and Hazardous Materials Safety Administration ( PHMSA ).

Under the Natural Gas Act, the FERC has authority to regulate gas transportation services in interstate commerce, including natural gas storage services. The FERC exercises jurisdiction over rates charged for services and the terms and conditions of service; the certification and construction of new facilities; the extension or abandonment of services and facilities; the maintenance of accounts and records, the acquisition and disposition of facilities; standards of conduct between affiliated entities; and various other matters. Regulated natural gas companies are prohibited from charging rates determined by the FERC to be unjust, unreasonable, or unduly discriminatory, and both the existing tariff rates and the proposed rates of regulated natural gas companies are subject to challenge.

The rates and terms and conditions of our natural gas storage and transportation services are found in the FERC-approved tariffs of Central New York Oil And Gas Company, L.L.C. ( CNYOG ), the owner of the Stagecoach facility and laterals; Steuben Gas Storage Company, the owner of the Steuben facility; Arlington Storage Company, LLC ( ASC ), the owner of the Thomas Corners and Seneca Lake facilities; and Tres Palacios Gas Storage LLC ( TPGS ), the owner of the Tres Palacios facility. CNYOG, ASC and TPGS are authorized to charge and collect market-based rates for storage services provided at the Stagecoach, Thomas Corners, Seneca Lake and Tres Palacios facilities, and CNYOG is authorized to charge and collected negotiated rates for transportation services provided by our North/South facilities. Steuben Gas Storage Company is authorized to charge and collect cost-of-service rates at the Steuben facility. Market-based and negotiated rate authority allows us to negotiate rates with individual customers based on market demand, which we then make public. A loss of market-based rate authority or any successful complaint or protest against the rates charged or provided by CNYOG, ASC or TPGS could have an adverse impact on our revenues.

On August 6, 2010, CNYOG filed an application with the FERC requesting authority to construct, operate and own the MARC I pipeline. On May 27, 2011, the FERC issued an Environmental Assessment ( EA ) for the project, in which FERC Staff proposed a finding of no significant impact and recommended the adoption of 22

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mitigation measures. We filed our initial comments to the EA in July 2011 and subsequently responded to numerous comments filed by interveners. Several interveners opposed to the development of natural gas infrastructure in the Northeast have argued that, among other things, the environmental impact of the MARC I pipeline must be more fully evaluated in an Environmental Impact Statement ( EIS ) before the FERC can issue a certificate authorizing the project. The preparation of an EIS could delay our FERC proceeding by an additional six-to-nine months. We do not expect the FERC to require an EIS, and we expect the FERC to issue an order granting the requested authorization in November 2011. We cannot, however, provide any assurances that the FERC will not require the preparation of an EIS or grant our requested authorization when anticipated, if at all.

We also plan to request FERC authorization to charge market-based rates for storage services provided by our Steuben natural gas facility. In particular, we intend to request FERC approval to merge Steuben Gas Storage Company into ASC and, as a result thereof, charge market-based rates for Steuben storage services under ASC s tariff. If our request is granted, we will have the ability to charge market-based rates for storage service provided by our Thomas Corners, Seneca Lake and Steuben facilities under one tariff (ASC s tariff), which will move us closer toward becoming an integrated natural gas storage and transportation hub in the Northeast. The ownership and operation of Steuben and Thomas Corners by ASC under its tariff will effectively enable Thomas Corners to be directly connected to Dominion and enable Steuben to be directly connected to TGP and Millennium, i.e., there will be no functional distinction between Thomas Corners and Steuben s interconnections once both facilities provide storage services under ASC s tariff.

Our pipelines used to store and transport natural gas are subject to regulation by the PHMSA under the Natural Gas Pipeline Safety Act of 1968 ( NGPSA ). The NGPSA regulates safety requirements in the design, installation, testing, construction, operation and maintenance of gas pipeline facilities. The NGPSA has since been amended by the Pipeline Safety Act of 1992, the Pipeline Safety Improvement Act of 2002, and the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006. These amendments, along with implementing regulations more recently adopted by PHMSA, have imposed additional safety requirements on pipeline operators such as the development of a written qualification program for individuals performing covered tasks on pipeline facilities and the implementation of pipeline integrity management programs. These integrity management plans require more frequent inspections and other preventative measures to ensure pipeline safety in high consequence areas, such as high population areas, areas unusually sensitive to environmental damage, and commercially navigable waterways. The PHMSA has approved our qualification programs, and we believe that we are in substantial compliance with these requirements.

In response to recent major pipeline accidents, including an explosion in a residential neighborhood in San Bruno, California, Congress is considering several bills proposing increased pipeline safety requirements. Among the changes being considered are significantly higher maximum civil penalties, new standards for excess flow and shutoff valves, public accessibility of pipeline information and expansion of safety requirements to classes of pipeline that were formerly exempt. The PHMSA is also considering changes to its natural gas transmission pipeline regulations to, among other things, strengthen integrity management requirements applicable to existing operators; strengthen or expand non-integrity pipeline management standards relating to such matters as valve spacing, automatic or remotely-controlled valves, corrosion protection, and gathering lines; and add new regulations to govern the safety of underground natural gas storage facilities including underground storage caverns and injection or withdrawal well piping that are not regulated today. We cannot predict the final outcome of these legislative efforts or the precise impact that compliance with any resulting new requirements may have on our business. Any new or expanded pipeline safety requirements could increase our cost of operation and impair our ability, or the ability of interconnected transportation facilities, to provide service during the period in which assessments and repairs take place, adversely affecting our business.

Our natural gas and NGL storage operations are also subject to non-rate regulation by state agencies. For example, the Railroad Commission of Texas ( RRC ) has jurisdiction over oil and gas wells drilled and produced, underground natural gas storage caverns and related facilities and pipelines used to transport oil or gas resources in Texas, and the NYSDEC has jurisdiction over the underground storage of natural gas and NGL and well drilling, conversion and plugging in New York. Accordingly, the RRC regulates aspects of Tres Palacios and the NYSDEC regulates aspects of our Stagecoach, Thomas Corners, Seneca Lake and Steuben natural gas storage facilities and our NGL storage facilities (including our Bath facility and our proposed Watkins Glen facility). Our inability to obtain, maintain or renew any material permit required to operate or expand our storage projects could have an adverse impact on our revenues.

Inergy Pipeline East, LLC, as the owner and operator of the 37.5-mile Inergy East intrastate natural gas pipeline (formerly known as the Seneca Lake east lateral pipeline), is subject to lightened regulation under NYPSC regulations and policies. Under lightened regulation, Inergy East is exempt from most NYPSC regulation applicable to the provision of retail service and, instead, must comply with limited corporate (e.g., obtaining approval prior to any transfer of its ownership interests or the issuance of debt securities) and operational and safety (e.g., filing of vegetation management plan and annual reports detailing the gas volumes transported over the pipeline) requirements regulated by the NYPSC.

On October 9, 2009, we filed an application with the NYSDEC for an underground storage permit for our Watkins Glen NGL storage facility. On November 17, 2010, the NYSDEC issued a Positive Declaration for the project. On August 17, 2011, the NYSDEC determined that the Draft Supplemental Environmental Impact Statement we submitted for the project was complete. A public hearing on the project was held on September 27, 2011, and a second public hearing was held on November 3, 2011. We expect to receive NYSDEC approval in the first calendar quarter of 2012, and to commence construction of the Watkins Glen facility immediately thereafter.

**Item 1A. Risk Factors**

**Risks Inherent in Our Business**

***Future acquisitions and completion of expansion projects will require significant amounts of debt and equity financing which may not be available to us on acceptable terms, or at all.***

We plan to fund our acquisitions and expansion capital expenditures, including any future expansions we may undertake, with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms or in the proportions that we expect, or at all, and we may be unable to refinance our revolving credit facility when it expires. In addition, we may be unable to obtain adequate funding under our current revolving credit facility because our lending counterparties may be unable to meet their funding obligations.

Global financial markets and economic conditions have been, and continue to be, disrupted and volatile. The debt and equity capital markets have been distressed. These issues, along with significant write-offs in the financial services sector, the re-pricing of credit risk and the current weak economic conditions may make it difficult to obtain funding.

The cost of raising money in the debt and equity capital markets has increased while the availability of funds from those markets generally has diminished. Also, as a result of concerns about the stability of financial markets generally and the solvency of our counterparties specifically, the cost of obtaining money from the credit markets generally has increased as many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity or on terms similar to our current debt and reduced and, in some cases, ceased to provide funding to borrowers.

A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, as well as the credit market and debt and equity capital market conditions discussed above could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement, which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance acquisitions or our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

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***If we do not continue to make acquisitions on economically acceptable terms, our future financial performance may be limited.***

Due to increased competition from alternative energy sources, the propane industry is not a growth industry. In addition, as a result of long-standing customer relationships that are typical in the retail home propane industry, the inconvenience of switching tanks and suppliers and propane s higher cost as compared to other energy sources, we may have difficulty in increasing our retail customer base other than through acquisitions. Therefore, while our operating objectives include promoting internal growth, our ability to grow depends principally on acquisitions. Our future financial performance depends on our ability to continue to make acquisitions at attractive prices. There is no assurance that we will be able to continue to identify attractive acquisition candidates in the future or that we will be able to acquire businesses on economically acceptable terms. In particular, competition for acquisitions in the propane business has intensified and become more costly. We may not be able to grow as rapidly as we expect through our acquisition of additional businesses for various reasons, including the following:

- We will use our cash from operations primarily to service our debt and for distributions to unitholders and reinvestment in our business. Consequently, the extent to which we are unable to use cash or access capital to pay for additional acquisitions may limit our growth and impair our operating results. Further, we are subject to certain debt incurrence covenants under our bank credit agreement and the indentures that govern our senior notes that may restrict our ability to incur additional debt to finance acquisitions.

- Although we intend to use our securities as acquisition currency, some prospective sellers may not be willing to accept our securities as consideration.

- We will use cash for capital expenditures related to expansion projects, which will reduce our cash available to pay for additional acquisitions.

Moreover, acquisitions involve potential risks, including:

- our inability to integrate the operations of recently acquired businesses;

- the diversion of management s attention from other business concerns;

- customer or key employee loss from the acquired businesses; and

- a significant increase in our indebtedness.

***Our growth strategy includes acquiring entities with lines of business that are distinct and separate from our existing operations, which could subject us to additional business and operating risks.***

Consistent with our announced growth strategy and our acquisition of the US Salt facility and related assets, we may acquire assets that have operations in new and distinct lines of business from our existing operations. Integration of new business segments is a complex, costly and time-consuming process and may involve assets in which we have limited operating experience. Failure to timely and successfully integrate acquired entities new lines of business with our existing operations may have a material adverse effect on our business, financial condition or results of operations. The difficulties of integrating new business segments with existing operations include, among other things:

- operating distinct business segments that require different operating strategies and different managerial expertise;

- the necessity of coordinating organizations, systems and facilities in different locations;
- integrating personnel with diverse business backgrounds and organizational cultures; and
- consolidating corporate and administrative functions.

In addition, the diversion of our attention and any delays or difficulties encountered in connection with the integration of the new business segments, such as unanticipated liabilities or costs, could harm our existing

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business, results of operations, financial condition or prospects. Furthermore, new lines of business will subject us to additional business and operating risks, which could have a material adverse effect on our financial condition or results of operations.

***We may be unable to successfully integrate our recent acquisitions.***

One of our primary business strategies is to grow through acquisitions. There is no assurance that we will successfully integrate acquisitions into our operations, or that we will achieve the desired profitability from our acquisitions. Failure to successfully integrate these substantial acquisitions could adversely affect our operations. The difficulties of combining the acquired operations include, among other things:

- operating a significantly larger combined organization and integrating additional retail and wholesale distribution operations to our existing supply, marketing and distribution operations;
- coordinating geographically disparate organizations, systems and facilities;
- integrating personnel from diverse business backgrounds and organizational cultures;
- consolidating corporate, technological and administrative functions;
- integrating internal controls, compliance under the Sarbanes-Oxley Act of 2002 and other corporate governance matters;
- the diversion of management s attention from other business concerns;
- customer or key employee loss from the acquired businesses;
- a significant increase in our indebtedness; and
- potential environmental or regulatory liabilities and title problems.

In addition, we may not realize all of the anticipated benefits from our acquisitions, such as cost-savings and revenue enhancements, for various reasons, including difficulties integrating operations and personnel, higher costs, unknown liabilities and fluctuations in markets.

***Our indebtedness may limit our ability to borrow additional funds, make distributions to our unitholders, or capitalize on acquisition or other business opportunities, in addition to impairing our ability to fulfill our debt obligation under our senior notes.***

As of September 30, 2011, we had $1.9 billion of total outstanding indebtedness. Our leverage, various limitations in the agreements governing our credit facility, other restrictions governing our indebtedness and the indentures governing our senior notes may reduce our ability to incur additional indebtedness, to engage in some transactions and to capitalize on acquisition or other business opportunities.

Our indebtedness and other financial obligations could have important consequences. For example, they could:

- make it more difficult for us to make distributions to our unitholders;

impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general partnership purposes or other purposes;

result in higher interest expense in the event of increases in interest rates since some of our debt is, and will continue to be, at variable rates of interest;

have a material adverse effect on us if we fail to comply with financial and restrictive covenants in our debt agreements and an event of default occurs as a result of that failure that is not cured or waived;

require us to dedicate a substantial portion of our cash flow to payments of our indebtedness and other financial obligations, thereby reducing the availability of our cash flow to fund working capital, capital expenditures and other general partnership requirements;

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- limit our flexibility in planning for, or reacting to, changes in our business and the propane industry; and
- place us at a competitive disadvantage compared to our competitors that have proportionately less debt.

If we are unable to meet our debt service obligations and other financial obligations, we could be forced to restructure or refinance our indebtedness and other financial transactions, seek additional equity capital or sell our assets. We may then be unable to obtain such financing or capital or sell our assets on satisfactory terms, if at all.

***A change of control could result in us facing substantial repayment obligations under our credit facility and our senior notes.***

Our bank credit agreement and the indentures governing our senior notes contain provisions relating to change of control of our general partner, our partnership and our operating company. If these provisions are triggered, our outstanding bank indebtedness may become due. In such an event, there is no assurance that we would be able to pay the indebtedness, in which case the lenders under our credit facility would have the right to foreclose on our assets, which would have a material adverse effect on us. There is no restriction on the ability of our general partners to enter into a transaction which would trigger the change of control provisions.

***Restrictive covenants in the agreements governing our indebtedness may reduce our operating flexibility.***

The indentures governing our outstanding senior notes and agreements governing our revolving credit facilities and other future indebtedness contain or may contain various covenants limiting our ability and the ability of our specified subsidiaries to, among other things:

- pay distributions on, redeem or repurchase our equity interests or redeem or repurchase our subordinated debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred securities;
- create or incur certain liens;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries; and
- create non-guarantor subsidiaries.

These restrictions could limit our ability and the ability of our subsidiaries to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general, conduct operations or otherwise take advantage of business opportunities that may arise. Our bank credit agreement contains covenants requiring us to maintain specified financial ratios and satisfy other financial conditions. We may be unable to meet those ratios and conditions. Any future breach of these covenants and our failure to meet any of those ratios and conditions could result in a default under the terms of our bank credit agreement, which could result in the acceleration of our debt and other financial obligations. If we were unable to repay these amounts, the lenders could initiate a bankruptcy proceeding or liquidation proceeding or proceed against the collateral.

***We are subject to operating and litigation risks that could adversely affect our operating results to the extent not covered by insurance.***

Our operations are subject to all operating hazards and risks incident to handling, storing, transporting and providing customers with combustible products such as propane and natural gas. As a result, we have been, and likely will be, a defendant in legal proceedings and litigation arising in the ordinary course of business. We maintain insurance policies with insurers in such amounts and with such coverages and deductibles as we believe are reasonable and prudent. However, our insurance may not be adequate to protect us from all material expenses related to potential future claims for personal injury and property damage. In addition, the occurrence of a serious accident, whether or not we are involved, may have an adverse effect on the public s desire to use our products.

***Our operations are subject to compliance with environmental laws and regulations that can adversely affect our results of operations and financial condition.***

Our operations are subject to stringent environmental laws and regulations of federal, state and local authorities. Such environmental laws and regulations impose numerous obligations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to comply with applicable laws and restrictions on the generation, handling, treatment, storage, disposal and transportation of certain materials and wastes. Failure to comply with such environmental laws and regulations can result in the assessment of substantial administrative, civil and criminal penalties, the imposition of remedial liabilities and even the issuance of injunctions restricting or prohibiting our activities. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. In the course of our operations, materials or wastes may have been spilled or released from properties owned or leased by us or on or under other locations where these materials or wastes have been taken for disposal. In addition, many of the properties owned or leased by us were previously operated by third parties whose management, disposal or release of materials and wastes was not under our control. Accordingly, we may be liable for the costs of cleaning up or remediating contamination arising out of our operations or as a result of activities by others who previously occupied or operated on properties now owned or leased by us. It is also possible that adoption of stricter environmental laws and regulations or more stringent interpretation of existing environmental laws and regulations in the future could result in additional costs or liabilities to us as well as the industry in general.

It is also possible that adoption of stricter environmental laws and regulations or more stringent interpretation of existing environmental laws and regulations in the future could result in additional costs or liabilities to us as well as the industry in general or otherwise adversely affect demand for the natural gas or NGLs we store as part of our midstream services. It is also possible that adoption of stricter environmental laws and regulations or more stringent interpretation of existing environmental laws and regulations in the future could result in additional costs or liabilities to us or our customers and also adversely affect demand for the natural gas or NGLs we store and transport as part of our business. For instance, the U.S. Environmental Protection Agency, or EPA, and other federal and state agencies are considering or have already commenced the study of potential adverse impacts that certain drilling methods (including hydraulic fracturing) may have on water quality and public health, with the U.S. Department of Energy having only recently released a report on August 11, 2011, recommending the implementation of a variety of measures to reduce the environmental impacts from shale-gas production. Similarly, the U.S. Congress and several states, including New York and Pennsylvania, have proposed or enacted legislation or regulations that are expected to make it more difficult or costly for exploration and production companies to produce natural gas and NGLs. These initiatives, enactments and regulations could have an indirect adverse impact on us by decreasing demand for the storage and transportation services that we offer.

***Cost reimbursements due our general partner may be substantial and will reduce the cash available for principal and interest on our outstanding indebtedness.***

We reimburse our general partner and its affiliates, including officers and directors of our general partner, for all expenses they incur on our behalf. The reimbursement of expenses could adversely affect our ability to make

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payments of principal and interest on our outstanding indebtedness. Our general partner has sole discretion to determine the amount of these expenses. In addition, our general partner and its affiliates provide us with services for which we are charged reasonable fees as determined by our general partner in its sole discretion.

***Failure to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act could cause us to incur additional expenditures of time and financial resources.***

We have completed the process of documenting and testing our internal control procedures in order to satisfy the requirements of Section 404 of the Sarbanes-Oxley Act, which requires annual management assessments of the effectiveness of our internal controls over financial reporting and a report by our independent registered public accounting firm on our controls over financial reporting. If, in the future, we fail to maintain the adequacy of our internal controls, as such standards are modified, supplemented or amended from time to time, we may not be able to ensure that we can conclude on an ongoing basis that we have effective internal controls over financial reporting in accordance with Section 404 of the Sarbanes-Oxley Act. Failure to achieve and maintain an effective internal control environment could cause us to incur substantial expenditures of management time and financial resources to identify and correct any such failure.

***Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating and capital costs and reduced demand for our storage services.***

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other greenhouse gases ( GHGs ) present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating GHG emissions under the Clean Air Act, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources, effective January 2, 2011, which could require greenhouse emission controls for those sources. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010, as well as certain onshore oil and natural gas production, processing, transmission, storage and distribution facilities on an annual basis, beginning in 2012 for emissions occurring in 2011.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emission allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas that is produced, which may decrease demand for our storage services. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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**Risks Related to Our Propane Operations**

***Since weather conditions may adversely affect the demand for propane, our financial condition and results of operations are vulnerable to, and will be adversely affected by, warm winters.***

Weather conditions have a significant impact on the demand for propane because many of our customers depend on propane principally for heating purposes. As a result, warm weather conditions will adversely impact our operating results and financial condition. Actual weather conditions can substantially change from one year to the next. Furthermore, warmer than normal temperatures in one or more regions in which we operate can significantly decrease the total volume of propane we sell. Consequently, our operating results may vary significantly due to actual changes in temperature. During seven of the last ten fiscal years temperatures were significantly warmer than normal in our areas of operation (based on the 30-year average consisting of years 1976 through 2005 published by the National Oceanic and Atmospheric Administration). We believe that our results of operations during these periods were adversely affected as a result of this warm weather.

***Sudden and sharp propane price increases that cannot be passed on to customers may adversely affect our profit margins.***

The propane industry is a margin-based business in which gross profits depend on the excess of sales prices over supply costs. As a result, our profitability is sensitive to changes in wholesale prices of propane caused by changes in supply or other market conditions. When there are sudden and sharp increases in the wholesale cost of propane, we may not be able to pass on these increases to our customers through retail or wholesale prices. Propane is a commodity and the price we pay for it can fluctuate significantly in response to changes in supply or other market conditions. We have no control over supply or market conditions. In addition, the timing of cost pass-throughs can significantly affect margins. Sudden and extended wholesale price increases could reduce our gross profits and could, if continued over an extended period of time, reduce demand by encouraging our retail customers to conserve or convert to alternative energy sources.

***The highly competitive nature of the retail propane business could cause us to lose customers or affect our ability to acquire new customers, thereby reducing our revenues.***

We have competitors and potential competitors who are larger and have substantially greater financial resources than we do. Also, because of relatively low barriers to entry into the retail propane business, numerous small retail propane distributors, as well as companies not engaged in retail propane distribution, may enter our markets and compete with us. Most of our propane retail branch locations compete with several marketers or distributors. The principal factors influencing competition with other retail marketers are:

- price;
- reliability and quality of service;
- responsiveness to customer needs;
- safety concerns;
- long-standing customer relationships;
- the inconvenience of switching tanks and suppliers; and
- the lack of growth in the industry.

We can make no assurances that we will be able to compete successfully on the basis of these factors. If a competitor attempts to increase market share by reducing prices, we may lose customers, which would reduce our revenues.

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***If we are not able to purchase propane from our principal suppliers, our results of operations would be adversely affected.***

Most of our total volume purchases are made under supply contracts that have a term of one year, are subject to annual renewal, and provide various pricing formulas. One of our suppliers, BP Amoco Corp., accounted for 14% of propane purchases during the fiscal year ended September 30, 2011. In the event that we are unable to purchase propane from our significant suppliers, our failure to obtain alternate sources of supply at competitive prices and on a timely basis may hurt our ability to satisfy customer demand, reduce our revenues and adversely affect our results of operations.

***Competition from other energy sources may cause us to lose customers, thereby reducing our revenues.***

Competition from other energy sources, including natural gas and electricity, has been increasing as a result of reduced regulation of many utilities, including natural gas and electricity. Propane is generally not competitive with natural gas in areas where natural gas pipelines already exist because natural gas is a less expensive source of energy than propane. The gradual expansion of natural gas distribution systems and availability of natural gas in many areas that previously depended upon propane could cause us to lose customers, thereby reducing our revenues.

***Our business would be adversely affected if service at our principal storage facilities or on the common carrier pipelines we use is interrupted.***

Historically, a substantial portion of the propane purchased to support our operations has originated at Conway, Kansas, Hattiesburg, Mississippi and Mont Belvieu, Texas and has been shipped to us through major common carrier pipelines. Any significant interruption in the service at these storage facilities or on the common carrier pipelines we use would adversely affect our ability to obtain propane.

***If we are not able to sell propane that we have purchased through wholesale supply agreements to either our own retail propane customers or to other retailers and wholesalers, the results of our operations would be adversely affected.***

We currently are party to propane supply contracts and expect to enter into additional propane supply contracts which require us to purchase substantially all the propane production from certain refineries. Our inability to sell the propane supply in our own propane distribution business, to other retail propane distributors or to other propane wholesalers would have a substantial adverse impact on our operating results and could adversely impact our capital liquidity. We are also a party to fixed price sale contracts with certain customers that are backed-up by propane supply contracts. If a significant number of our customers default under these fixed price contracts the results of our operations would be adversely affected.

***Energy efficiency and new technology may reduce the demand for propane and adversely affect our operating results.***

Increased conservation and technological advances, including installation of improved insulation and the development of more efficient furnaces and other heating devices, have adversely affected the demand for propane by retail customers. Future conservation measures or technological advances in heating, conservation, energy generation or other devices might reduce demand for propane and adversely affect our operating results.

***Due to our limited asset diversification, adverse developments in our propane business could adversely affect our operating results and reduce our ability to make distributions to our unitholders.***

We rely substantially on the revenues generated from our propane business. Due to our limited asset diversification, an adverse development in this business would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets.

**Risks Related to Our Midstream Operations**

***Our natural gas operations are subject to extensive regulation by federal, state and local regulatory authorities; regulatory measures adopted by such authorities could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.***

Our natural gas storage and transportation business is subject to extensive regulation by federal, state and local regulatory authorities. Because we transport natural gas in interstate commerce and we store natural gas that is transported in interstate commerce, our natural gas storage and transportation facilities are subject to comprehensive regulation by the FERC under the Natural Gas Act.

Federal regulation under the Natural Gas Act extends to such matters as rates, operating terms and conditions of service; the form of tariffs governing service; the types of services we may offer to our customers; the certification and construction of new, or the expansion of existing, facilities; the acquisition, extension, disposition or abandonment of facilities; contracts for service between storage and transportation providers and their customers; creditworthiness and credit support requirements; the maintenance of accounts and records; relationships among affiliated companies involved in certain aspects of the natural gas business; the initiation and discontinuation of services; and various other matters. Natural gas companies may not charge rates that, upon review by FERC, are found to be unjust and unreasonable or unduly discriminatory. The rates and terms and conditions for interstate services provided by the Steuben facility are found in the FERC-approved tariff of Steuben Gas Storage Company. The rates and terms and conditions for interstate services provided by Stagecoach are found in the FERC-approved tariff of CNYOG. The rates and terms and conditions for interstate services provided by the Thomas Corners and Seneca Lake facilities are found in the FERC-approved tariff of ASC. The rates of terms and conditions for interstate services provided by Tres Palacios are found in the FERC-approved tariff of TPGS.

Under the Natural Gas Act, existing interstate transportation and storage rates may be challenged by complaint and are subject to prospective change by FERC. Rate increases proposed by a regulated pipeline or storage provider may also be challenged and such increases may be rejected by FERC. We currently hold authority from FERC to charge and collect (i) market-based rates for interstate storage services provided at the Stagecoach, Thomas Corners, Seneca Lake and Tres Palacios facilities and (ii) negotiated rates for interstate transportation services provided over the Stagecoach north and south lateral pipelines. FERC s market-based rate policy allows regulated entities to charge rates different from, and in some cases, less than, those which would be permitted under traditional cost-of-service regulation. Among the sorts of changes in circumstances that could raise market power concerns would be an expansion of capacity, acquisitions or other changes in market dynamics. There can be no guarantee that we will be allowed to continue to operate under such rate structures for the remainder of those assets operating lives. Any successful challenge against rates charged for our storage and transportation services, or our loss of market-based rate authority or negotiated rate authority, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. Our market-based rate authority for our natural gas storage facilities may be subject to review and possible revocation if FERC determines that we have the ability to exercise market power in our market area. If we were to lose our ability to charge market-based rates, we would be required to file rates based on our cost of providing service, including a reasonable rate of return. Cost-of-service rates are likely to be lower than our current market-based rates.

Interstate storage services provided at the Steuben facility are currently subject to cost-of-service regulation. FERC s cost-of-service regulations limit the maximum rates for storage services to the cost of providing service plus a reasonable return. In each rate case, the FERC must approve service costs, the allocation of costs, the allowed rate of return on capital investment, rate design, and other rate factors. A negative determination on any of these rate factors could adversely affect our business, financial condition, results of operations and ability to make distributions. Although we intend to request FERC authorization to charge market-based rates for Steuben storage services, we cannot guarantee that the FERC will grant that authorization. If the FERC does not authorize us to charge market-based rates at the Steuben facility, we will continue to charge cost-of-service rates.

There can be no assurance that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity and transportation and storage facilities. Failure to comply with applicable regulations under the Natural Gas Act, the Natural Gas Policy Act of 1978, the Pipeline Safety Act of 1968 and certain other laws, and with implementing regulations associated with these laws, could result in the imposition of administrative and criminal remedies and civil penalties of up to $1,000,000 per day, per violation.

***We may not be able to renew or replace expiring storage contracts.***

Our primary exposure to market risk occurs at the time our existing storage contracts expire and are subject to renegotiation and renewal. As of September 30, 2011, the weighted-average remaining tenor of our existing portfolio of firm storage contracts is approximately 2.8 years. The extension or replacement of existing contracts depends on a number of factors beyond our control, including the level of existing and new competition to provide storage services to our markets; the macroeconomic factors affecting natural gas and NGL storage economics for our current and potential customers; the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets; the extent to which the customers in our markets are willing to contract on a long-term basis; and the effects of federal, state or local regulations on the contracting practices of our customers. Any failure to extend or replace a significant portion of our existing contracts, or extending or replacing them at unfavorable or lower rates, could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

***We depend on third-party pipelines connected to our natural gas facilities and pipelines, and we could be negatively impacted by circumstances beyond our control that temporarily or permanently interrupt the operation of such third-party pipelines.***

We depend on the continued operation of third-party pipelines that provide delivery options to and from our storage facilities, and to which our transportation pipelines are connected. This is true particularly in the Northeast, where our Stagecoach facility depends on TGP s 300 Line and Millennium, currently the only pipelines to which it is directly interconnected; our Steuben and Seneca Lake facilities depend on Dominion; and our Thomas Corners facility depends on TGP s 400 Line and Millennium. These pipelines are owned by parties not affiliated with us. Any temporary or permanent interruption at any key pipeline or other interconnect point with our natural gas storage facilities that causes a material reduction in the volume of storage or transportation services provided by us could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

In addition, the rates charged by the interconnected pipelines for transportation to and from our facilities and pipelines affect the utilization and value of our services. Significant changes in the rates charged by these pipelines or the rates charged by other pipelines with which the interconnected pipelines compete could also have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

***Expanding our business by constructing new midstream assets subjects us to risks.***

We have a number of growth projects, such as the MARC I pipeline, the Watkins Glen NGL storage development project, the expansion of Seneca Lake natural gas storage facility (Gallery 2) by 0.6 Bcf of working gas storage capacity, the North/South II expansion project, and the development of up to 10 Bcf of natural gas storage capacity using existing cavern capacity on US Salt properties. The development and construction of storage facilities and pipelines involves numerous regulatory, environmental, political and legal uncertainties beyond our control and may require the expenditure of significant amounts of capital. When we undertake these projects, they may not be completed on schedule, at the budgeted cost or at all. Moreover, our revenues may not increase immediately upon the expenditure of funds on a particular project. For instance, if we build a new midstream asset, the construction will occur over an extended period of time, and we will not receive material

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increases in revenues until the project is placed in service. Furthermore, we may construct facilities to capture anticipated future growth in production and/or demand in a region in which such growth does not materialize. As a result, new facilities may not be able to attract enough throughput to achieve our expected investment return, which could adversely affect our business, financial condition, results of operations and ability to make distributions.

Certain of our internal growth projects must receive certificate authority from FERC and other government agencies prior to construction, such as our MARC I pipeline. The approval process for storage and transportation projects, particularly those located in the Northeast, has become increasingly challenging, due in part to state and local concerns related to unregulated exploration and production and gathering activities in new production areas (including the Marcellus shale play). We cannot guarantee such certificate authorization will be granted or, if granted, that such authorization will be free of burdensome or expensive conditions.

***Increased competition from other companies that provide storage or transportation services, or services that can substitute for storage or transportation services, could have a negative impact on the demand for our services, which could adversely affect our financial results.***

We compete primarily with other providers of storage and transportation services that own or operate natural gas and NGL storage facilities and natural gas pipelines. Such competitors include independent storage developers and operators, local distribution companies, interstate and intrastate natural gas transmission companies with storage facilities connected to their pipelines, and other midstream companies. Some of our competitors have greater financial, managerial and other resources than we do and control substantially more storage and transportation capacity than we do. Our principal natural gas storage competitors include, among others, Dominion Resources, Inc., NiSource Inc. and El Paso Corporation. These major pipeline natural gas transmission companies have existing storage facilities connected to their systems that compete with certain of our facilities. In addition, our customers may develop their own storage and transportation assets in lieu of using ours. FERC has adopted a policy that favors authorization of new storage projects, and there are numerous natural gas storage options in the New York/Pennsylvania and Texas geographic markets. Pending and future construction projects, if and when brought on-line, may also compete with our natural gas storage operations. Such projects may include FERC-certificated storage expansions and greenfield construction projects.

We also compete with the numerous alternatives to storage available to customers, including pipeline balancing/no-notice services, seasonal/swing services provided by pipelines and marketers and on-system liquefied natural gas facilities. In addition, natural gas as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas storage and transportation services.

If our competitors substantially increase the resources they devote to the development and marketing of competitive services or substantially decrease the prices at which they offer their services, we may be unable to compete effectively. Some of these competitors may expand or construct new storage or transportation assets that would create additional competition for us. The expansion of storage or transportation assets and construction activities of our competitors could result in storage or transportation capacity in excess of actual demand, which could reduce the demand for our services, and potentially reduce the rates that we receive for our services.

All of these competitive pressures could make it more difficult for us to retain our existing customers and/or attract new customers as we seek to expand our business, which could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions. In addition, competition could intensify the negative impact of factors that decrease demand for natural gas and NGL storage and transportation in our markets, such as adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that increase the cost or limit the use of natural gas.

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***We expect to derive a significant portion of our revenues from our storage and transportation operations from a limited number of customers, and the loss of one or more of these customers could result in a significant loss of revenues and cash flow.***

We expect to derive a significant portion of our revenues and cash flow in connection with our natural gas and NGL storage and transportation operations from a limited number of customers. The loss, nonpayment, nonperformance or impaired creditworthiness of one of these customers could have a material adverse effect on our business, results of operations and financial condition.

***Any significant and prolonged change in or stabilization of natural gas prices could have a negative impact on our natural gas storage business.***

Historically, natural gas prices have been seasonal and volatile, which has enhanced demand for our storage services. The natural gas storage business has benefited from significant price fluctuations resulting from seasonal price sensitivity, which impacts the level of demand for our services and the rates we are able to charge for such services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If volatility and seasonality in the natural gas industry decrease, because of increased production capacity or otherwise, the demand for our services and the prices that we will be able to charge for those services may decline.

In addition to volatility and seasonality, an extended period of high natural gas prices would increase the cost of acquiring base gas and likely place upward pressure on the costs of associated expansion activities. An extended period of low natural gas prices could adversely impact storage values for some period of time until market conditions adjust. These commodity price impacts could have a negative impact on our business, financial condition, results of operations and ability to make distributions.

***We are exposed to the credit risk of our customers in the ordinary course of our business.***

We extend credit to our customers as a normal part of our business. As a result, we are exposed to the risk of loss resulting from the nonpayment and/or nonperformance of our customers. While we have established credit policies that include assessing the creditworthiness of our customers as permitted by our FERC-approved gas tariffs and requiring appropriate terms or credit support from them based on the results of such assessments, there can be no assurance that we have adequately assessed the creditworthiness of our existing or future customers or that there will not be unanticipated deterioration in their creditworthiness. Resulting nonpayment and/or nonperformance by our customers could have a material adverse effect on our business, financial condition, results of operations and ability to make distributions.

Additionally, in instances where we loan natural gas to third parties, the magnitude of our credit risk is significantly increased, as the failure of the third party to return the loaned volumes would result in losses equal to the full value of the loaned natural gas rather than, in the case of firm storage or hub services contracts, losses equal to fees on volumes nominated for injection or withdrawal.

***The fees charged by us to third parties under storage, transportation and processing agreements may not escalate sufficiently to cover increases in costs, and those agreements may be suspended in some circumstances.***

Our costs may increase at a rate greater than the rate that the fees we charge to third parties increase pursuant to our contracts with them. In addition, some third parties obligations under their agreements with us may be permanently or temporarily reduced upon the occurrence of certain events, some of which are beyond our control, including force majeure events wherein the supply of natural gas is curtailed or cut off. Force majeure events include (but are not limited to) revolutions, wars, acts of enemies, embargoes, import or export restrictions, strikes, lockouts, fires, storms, floods, acts of God, explosions, mechanical or physical failures of our equipment or facilities or those of third parties. If the escalation of fees is insufficient to cover increased costs or if any third party suspends or terminates its contracts with us, our business, financial condition, results of operations and ability to make distributions could be materially adversely affected.

***Our business would be adversely affected if operations at any of our facilities were interrupted.***

Our operations are dependent upon the infrastructure that we have developed, including, storage facilities and various means of transportation. Any significant interruption at these facilities or pipelines or our customers inability to transmit natural gas to or from these facilities or pipelines for any reason would adversely affect our results of operations.

***Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which we are not fully insured, our operations and financial results could be adversely affected.***

Our midstream operations are subject to all of the risks and hazards inherent in the natural gas and NGL businesses, including:

- reduction of our available storage capacity at our salt caverns over time due to (i) unexpected increases in the temperature of our caverns, which reduces capacity as a result of the expansion of the stored natural gas, (ii) the long-term effect of pressure differentials between the caverns and the surrounding salt formations (known as salt creep ) or (iii) problems with the structural integrity of our salt caverns;
- subsidence of the geological structures where we store natural gas and NGLs;
- risks and hazards inherent in drilling operations associated with the development of new caverns;
- problems maintaining the wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our storage facilities;
- damage to our facilities and properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism, third parties (including from construction, farm and utility equipment), equipment or material failures, pipeline or vessel ruptures or corrosion, explosions and other incidents;
- leaks, migrations or losses of natural gas and NGLs;
- collapse of storage caverns;
- operator error;
- environmental pollution or other environmental issues, including drinking water contamination associated with our raw water or water disposal wells or our water treatment facilities; and
- other industry hazards that could result in the suspension of operations.

These risks could result in substantial losses due to breaches of contractual commitments, personal injury and/or loss of life, damage to and destruction of property and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of our operations. A natural disaster or other hazard affecting the areas in which we operate could have a material adverse effect on our operations. We are not fully insured against all risks inherent in our business. In addition, we are not insured against all environmental accidents that might occur, some of which may result in toxic tort claims. If a significant accident or event occurs for which we are not fully insured, it could result in a material adverse effect on our business, financial condition, results of operations and ability to make distributions. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of market conditions, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance

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could become unavailable or available only for reduced amounts of coverage. Additionally, we may be unable to recover from prior owners of our assets, pursuant to our indemnification rights, for potential environmental liabilities.

**Risks Inherent in an Investment in Us**

***Unitholders have less ability to elect or remove management than holders of common stock in a corporation.***

Unlike the holders of common stock in a corporation, unitholders have only limited voting rights on matters affecting our business, and therefore limited ability to influence management s decisions regarding our business. Unitholders did not elect, and do not have the right to elect, our general partner or its board of directors on an annual or other continuing basis. The board of directors of our general partner is chosen by the sole member of our general partner, Inergy Holdings, L.P. John J. Sherman, who currently is the only voting member of the general partner of Inergy Holdings, effectively has the authority to appoint all of our directors. Although our general partner has a fiduciary duty to manage our partnership in a manner beneficial to Inergy, L.P. and our unitholders, the directors of our general partner also have a fiduciary duty to manage our general partner in a manner beneficial to its member, Inergy Holdings, L.P.

If unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. Our general partner generally may not be removed except upon the vote of the holders of 66 $^{2}/3$% of the outstanding units voting together as a single class.

Our unitholders voting rights are further restricted by a provision in our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partners and their affiliates, cannot be voted on any matter.

***The control of our general partner may be transferred to a third party without unitholder consent.***

Our general partner may transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of its assets without the consent of our unitholders. Furthermore, there is no restriction in our partnership agreement on the ability of the owner of our general partner, Inergy Holdings, L.P., from transferring its ownership interest in our general partner to a third party. The new owner of our general partner would then be in a position to replace the board of directors and officers of our general partner with its own choices and to control the decisions taken by our board of directors and officers.

***Cost reimbursements due our general partner may be substantial and reduce our ability to pay the minimum quarterly distribution.***

Before making any distributions on our units, we will reimburse our general partner for all expenses it has incurred on our behalf. In addition, our general partners and their affiliates may provide us with services for which we will be charged reasonable fees as determined by our general partner. The reimbursement of these expenses and the payment of these fees could adversely affect our ability to make distributions to you. Our general partner has sole discretion to determine the amount of these expenses and fees.

***We may issue additional common units without unitholder approval, which would dilute our unitholders existing ownership interests.***

We may issue an unlimited number of limited partner interests of any type without the approval of unitholders. The issuance of additional common units or other equity securities of equal rank will have the following effects:

- the proportionate ownership interest of our existing unitholders in us will decrease;

- the amount of cash available for distribution on each common unit or partnership security may decrease;

the relative voting strength of each previously outstanding common unit will be diminished; and

the market price of the common units or partnership securities may decline.

***Our cash distribution policy limits our ability to grow.***

Because we distribute all of our available cash, our growth may not be as rapid as businesses that reinvest their available cash to expand ongoing operations. If we issue additional units or incur debt to fund acquisitions and growth capital expenditures, the payment of distributions on those additional units or interest on that debt could increase the risk that we will be unable to maintain or increase our per unit distribution level.

**Tax Risks to Common Unitholders**

***The tax treatment of publicly traded partnerships is subject to potential legislative, judicial or administrative changes. If we were treated as a corporation for federal income tax purposes, or if we were to become subject to a material amount of state or local taxation, then our cash available for distribution to our unitholders would be substantially reduced.***

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes. A publicly traded partnership such as us may be treated as a corporation for federal income tax purposes unless it satisfies requirements regarding the sources of its income. Based on our current operations we believe that we are treated as a partnership rather than a corporation; however, a change in our business could cause us to be treated as a corporation for federal income tax purposes.

In addition, current law may change so as to cause us to be treated as a corporation for federal income tax purposes. For example, members of Congress have recently considered substantive changes to the existing federal income tax laws that would affect the tax treatment of certain publicly traded partnerships. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available to pay distributions would be reduced. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution amount and the target distribution amount will be adjusted to reflect the impact of that law on us.

If we were treated as a corporation for federal income tax purposes, we would be obligated to pay federal income tax on our taxable income at the corporate tax rate, currently a maximum rate of 35%, as well as any applicable state income tax. Distributions to our unitholders generally would be taxed to them in the same manner as distributions from a corporation, and none of our income, gain, loss, deduction or credit would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, our treatment as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

***If the IRS contests the federal income tax positions we take, the market for our common units may be adversely impacted and the cost of any IRS contest will reduce our cash available for distribution to you.***

We have not requested a ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, the costs of any contest with the IRS will be borne indirectly by you and our general partner because the costs will reduce our cash available for distribution.

***You may be required to pay taxes on your share of our income even if you do not receive cash distributions from us.***

Because you will be treated as a partner in us for federal income tax purposes, we will allocate a share of our taxable income to you which could be different in amount than the cash we distribute to you, and you may be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from that income.

***Tax gain or loss on the disposition of our common units could be more or less than expected.***

If you sell your common units, you will recognize a gain or loss equal to the difference between your amount realized and your tax basis in those common units. Because distributions in excess of your allocable share of our total net taxable income result in a reduction in your tax basis in your common units, the amount, if any, of such prior excess distributions with respect to the units you sell will, in effect, become taxable income to you if you sell such units at a price greater than your tax basis in those common units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture of depreciation deductions. In addition, because the amount realized includes a unitholder s share of our nonrecourse liabilities, if you sell your units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

***Tax-exempt entities, regulated investment companies and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.***

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes imposed at the highest effective applicable tax rate, and non-U.S. persons will be required to file U. S. federal income tax returns and pay tax on their share of our taxable income. If you are a tax-exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

***We treat each purchaser of our common units as having the same tax benefits without regard to the specific common units purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.***

To maintain the uniformity of the economic and tax characteristics of our common units, we have adopted certain depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. These positions may result in an understatement of deductions and an overstatement of income to our unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding units. A subsequent holder of those units may be entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). But, because we cannot identify these units once they are traded by the initial holder, we do not allocate any subsequent holder of a unit any such amortization deduction. This approach may understate deductions available to those unitholders who own those units and may result in those unitholders reporting that they have a higher tax basis in their units than would be the case if the IRS strictly applied Treasury Regulations relating to these depreciation or amortization adjustments. This, in turn, may result in those unitholders reporting less gain or more loss on a sale of their units than would be the case if the IRS strictly applied those Treasury Regulations.

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The IRS may challenge the manner in which we calculate our unitholder s basis adjustment under Section 743(b). If so, because the specific unitholders to which this issue relates cannot be identified, the IRS may assert adjustments to all unitholders selling units within the period under audit. A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our unitholders. It also could affect the gain from a unitholder s sale of common units or result in audit adjustments to our unitholders tax returns without the benefit of additional deductions. Consequently, a successful IRS challenge could have a negative impact on the value of the common units.

***We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.***

We prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations. Recently, the U.S. Treasury Department issued proposed Treasury Regulations that provide a safe harbor pursuant to which publicly traded partnerships may use a similar monthly simplifying convention to allocate tax items among transferor and transferee unitholders. Nonetheless, the proposed regulations do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

***A unitholder whose units are loaned to a short seller to cover a short sale of units may be considered as having disposed of those units. If so, that unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.***

If you loan your units to a short seller to cover a short sale of units, you may be considered as having disposed of the loaned units, and you may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and you may recognize gain or loss from such disposition. During the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by you and any cash distributions you receive as to those units could be fully taxable as ordinary income. To assure your status as a partner and avoid the risk of gain recognition from a loan to a short seller you are urged to modify any applicable brokerage account agreements to prohibit your broker from borrowing your units.

***The sale or exchange of 50% or more of our capital and profits interests within a twelve-month period will result in the termination of our partnership for federal income tax purposes.***

We will be considered to have constructively terminated as a partnership for federal income tax purposes if there is a sale or exchange within a twelve-month period of 50% or more of the total interests in our capital and profits. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders which could result in us filing two tax returns (and unitholders receiving two Schedule K-1s) for one calendar year. Our termination could also result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in its taxable income for the year of termination. Our termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for federal income tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred. Pursuant to an IRS relief procedure a publicly traded partnership that has technically terminated may request special relief which, if granted by the IRS, among other things, would permit the partnership to provide only a single Schedule K-1 to unitholders for the tax years in which the termination occurs.

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***Our unitholders will likely be subject to state and local taxes and return filing requirements in states where they do not live as a result of investing in our common units.***

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes, estate, inheritance or intangible taxes and foreign taxes that are imposed by the various jurisdictions in which we do business or own property and in which they do not reside. We own property and conduct business in various parts of the United States. Unitholders may be required to file state and local income tax returns in many or all of the jurisdictions in which we do business or own property. Further, unitholders may be subject to penalties for failure to comply with those requirements. It is our unitholders responsibility to file all required U. S. federal, state, local and foreign tax returns.

**Item 1B. Unresolved Staff Comments.**

None.

**Item 2. Properties.**

As of October 31, 2011, we owned 205 of our 338 retail propane customer service centers and leased the remaining centers. For more information concerning the location of our customer service centers see Retail Propane under Item 1. We lease our Kansas City, Missouri headquarters. We lease underground storage facilities with an aggregate capacity of 49.3 million gallons of propane and butane at eight locations under annual lease agreements. In addition, we own two underground storage facilities with an aggregate capacity of 71.6 million gallons of propane and butane. We also lease capacity in several pipelines pursuant to annual lease agreements.

Tank ownership and control at customer locations are important components to our retail propane operations and customer retention. As of September 30, 2011, we owned the following:

- 1,375 bulk storage tanks at approximately 700 locations with typical capacities of 12,000 to 30,000 gallons;
- 500,000 stationary customer storage tanks with typical capacities of 100 to 1,200 gallons; and
- 200,000 portable propane cylinders with typical capacities of up to 35 gallons.

We own the following midstream assets as discussed in Item 1:

- Stagecoach natural gas storage facility;
- Thomas Corners natural gas storage facility;
- Steuben natural gas storage facility;
- Tres Palacios natural gas storage facility;
- Seneca Lake natural gas storage facility;

- facilities comprising our West Coast NGL business;
- Inergy East intrastate natural gas pipeline;
- Bath NGL storage facility; and
- US Salt plant.

We believe that we have satisfactory title or valid rights to use all of our material properties. Although some of these properties are subject to liabilities and leases, liens for taxes not yet due and payable, encumbrances securing payment obligations under non-competition agreements entered in connection with acquisitions and immaterial encumbrances, easements and restrictions, we do not believe that any of these burdens will materially

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interfere with our continued use of these properties in our business, taken as a whole. Our obligations under our credit facility are secured by liens and mortgages on our fee-owned real and personal property, except real property located in New York.

In addition, we believe that we have, or are in the process of obtaining, all required material approvals, authorizations, orders, licenses, permits, franchises and consents of, and have obtained or made all required material registrations, qualifications and filings with, the various state and local governmental and regulatory authorities that relate to ownership of our properties or the operation of our business.

**Item 3. Legal Proceedings.**

Our operations are subject to all operating hazards and risks normally incidental to handling, storing, transporting and otherwise providing for use by consumers of combustible liquids such as propane. As a result, at any given time we are a defendant in various legal proceedings and litigation arising in the ordinary course of business. We maintain insurance policies with insurers in amounts and with coverages and deductibles as the general partner believes are reasonable and prudent. However, we cannot assure you that this insurance will be adequate to protect us from all material expenses related to potential future claims for personal and property damage or that these levels of insurance will be available in the future at economical prices.

Following the announcement of the Merger Agreement, two unitholder class action lawsuits were filed in the Court of Chancery of the State of Delaware challenging the proposed merger (Joel A. Gerber v. Inergy GP, LLC et al., No. 5864 and G-2 Trading LLC v. Inergy GP, LLC et al., No. 5816) (collectively, the Inergy Unitholder Lawsuits ). The parties to the Inergy Unitholder Lawsuits have entered into a Memorandum of Understanding whereby in consideration for the settlement and dismissal of the claims, the individual Class B unitholders will forego and relinquish a total of 135,539 Class B units to be received as distributions following the date on which the settlement and dismissal becomes final and no longer appealable. The parties are waiting on court approval of the proposed settlement.

**Item 4. Removed and Reserved.**

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## PART II

### Item 5. Market for Registrant s Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.

From July 31, 2001 to March 23, 2010, our common units representing limited partner interests were traded on NASDAQ s Global Select National Market under the symbol NRGY. On March 24, 2010, our common units representing limited partner interests began trading on The New York Stock Exchange under the symbol NRGY. The following table sets forth the range of high and low bid prices of the common units, as reported by NASDAQ and the NYSE, as well as the amount of cash distributions declared per common unit for the periods indicated.

| Quarters Ended: | Low | High | Cash Distribution Per Unit |
|---|---|---|---|
| Fiscal 2011: | | | |
| September 30, 2011 | $ 24.91 | $ 35.90 | $ 0.705 |
| June 30, 2011 | 33.52 | 41.22 | 0.705 |
| March 31, 2011 | 38.49 | 42.75 | 0.705 |
| December 31, 2010 | 37.25 | 41.92 | 0.705 |
| Fiscal 2010: | | | |
| September 30, 2010 | $ 35.56 | $ 43.95 | $ 0.705 |
| June 30, 2010 | 30.35 | 39.94 | 0.705 |
| March 31, 2010 | 32.48 | 38.04 | 0.695 |
| December 31, 2009 | 28.70 | 36.24 | 0.685 |

As of November 7, 2011, we had issued and outstanding 119,107,279 common units, 4,867,252 Class A units and 12,165,499 Class B units, which were held by 212, 2 and 20 unitholders of record, respectively.

Our company makes quarterly distributions to the partners within approximately 45 days after the end of each fiscal quarter in an aggregate amount equal to our available cash (as defined) for such quarter. Available cash generally means, with respect to each fiscal quarter, all cash on hand at the end of the quarter less the amount of cash that the general partner determines in its reasonable discretion is necessary or appropriate to:

- provide for the proper conduct of our business;
- comply with applicable law, any of our debt instruments, or other agreements; or
- provide funds for distributions to unitholders for any one or more of the next four quarters;

plus all cash on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter. Working capital borrowings are generally borrowings that are made under our working capital facility and in all cases are used solely for working capital purposes or to pay distributions to partners. The full definition of available cash is set forth in our partnership agreement (as amended), which is incorporated by reference herein as an exhibit to this report.

**Issuance of Class A Units and Class B Units**

On November 5, 2010, in connection with the Simplification Transaction, we issued 4,867,252 Class A units and 11,568,560 Class B units.

**Incentive Distribution Rights**

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash after a minimum quarterly distribution and certain target distribution levels have been achieved. All incentive distribution rights were eliminated as a result of the

Simplification Transaction.

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The following table sets forth in tabular format, a summary of our company s equity compensation plan information as of September 30, 2011:

**Equity Compensation Plan Information**

| Plan category | Number of securities to be issued upon exercise of outstanding options, warrants and rights (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | | | |
| Equity compensation plans not approved by security holders | 253,953 | $ 15.29 | 4,162,505 |
| Total | 253,953 | $ 15.29 | 4,162,505 |

**Item 6. Selected Financial Data.**

The following tables set forth selected consolidated financial data and other operating data of Inergy, L.P. The selected historical consolidated financial data of Inergy, L.P. as of and for the years ended September 30, 2011, 2010, 2009, 2008, and 2007, are derived from the audited consolidated financial statements of Inergy, L.P and Inergy Partners, LLC. Financial information for the years ended September 30, 2010, 2009, 2008 and 2007, have been revised to reflect the Merger. The historical consolidated financial data of Inergy, L.P. and Inergy Partners, LLC include the results of operations of its acquisitions from the effective date of the respective acquisitions.

EBITDA shown in the table below is defined as income before income taxes, plus net interest expense and depreciation and amortization expense. Adjusted EBITDA represents EBITDA excluding the gain or loss on derivative contracts associated with retail propane fixed price sales contracts, the gain or loss on the disposal of assets, long-term incentive and equity compensation expenses, transaction costs, net income attributable to non-controlling partners and interest, tax, depreciation and amortization expense attributable to non-controlling partners. Transaction costs are third party professional fees and other costs that are incurred in conjunction with closing a transaction. EBITDA and Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with generally accepted accounting principles as those items are used to measure operating performance, liquidity or ability to service debt obligations. We believe that EBITDA provides additional information for evaluating our ability to make the minimum quarterly distribution and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information for evaluating our financial performance without regard to our financing methods, capital structure and historical cost basis. EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA and Adjusted EBITDA or similarly titled measures used by other corporations or partnerships.

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The data in the following tables should be read together with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included in this report. The tables should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations under Item 7.

| | Inergy L.P. Years Ended September 30, (in millions, except per unit and unit data) | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| **Statement of Operations Data:** | | | | | |
| Revenues | $ 2,153.8 | $ 1,786.0 | $ 1,570.6 | $ 1,878.9 | $ 1,483.1 |
| Cost of product sold (excluding depreciation and amortization as shown below): | 1,476.0 | 1,165.9 | 996.9 | 1,376.7 | 1,026.1 |
| Expenses: | | | | | |
| Operating and administrative | 323.3 | 310.7 | 280.5 | 266.6 | 248.6 |
| Depreciation and amortization | 191.8 | 161.8 | 115.8 | 98.0 | 83.4 |
| Loss on disposal of assets | 8.2 | 11.5 | 5.2 | 11.5 | 8.0 |
| Operating income | 154.5 | 136.1 | 172.2 | 126.1 | 117.0 |
| Other income (expense): | | | | | |
| Interest expense, net | (113.5) | (91.5) | (70.5) | (62.6) | (54.4) |
| Early extinguishment of debt | (52.1) | | | | |
| Other income | 1.2 | 2.0 | 0.1 | 1.0 | 1.9 |
| Income (loss) before gain on issuance of units in subsidiary and income taxes | (9.9) | 46.6 | 101.8 | 64.5 | 64.5 |
| Gain on issuance of units in subsidiary | | | 8.0 | | 80.6 |
| Provision for income taxes | 0.7 | 0.2 | 1.7 | 1.4 | 6.5 |
| Net income (loss) | (10.6) | 46.4 | 108.1 | 63.1 | 138.6 |
| Net (income) loss attributable to non-controlling partners | 28.2 | 15.4 | (51.0) | (27.6) | (36.0) |
| Net income attributable to partners | $ 17.6 | $ 61.8 | $ 57.1 | $ 35.5 | $ 102.6 |
| Net income per limited partner unit: | | | | | |
| Basic[d] | $ 0.17 | $ 1.73 | $ 1.62 | $ 1.01 | $ 2.96 |
| Diluted[d] | $ 0.15 | $ 1.29 | $ 1.21 | $ 0.75 | $ 2.19 |
| Weighted-average limited partners units outstanding (*in thousands*): | | | | | |
| Basic[d] | 105,732 | 35,726 | 35,197 | 35,049 | 34,636 |
| Diluted[d] | 117,684 | 48,002 | 47,036 | 47,106 | 46,792 |
| Cash distributions paid per unit[e] | $ 2.82 | $ 2.76 | $ 2.60 | $ 2.44 | $ 2.28 |

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| | 2011 | 2010 | 2009 | 2008 | 2007 |
|---|---|---|---|---|---|
| **Balance Sheet Data (end of period):** | | | | | |
| Total assets[c] | $ 3,340.9 | $ 3,117.8 | $ 2,154.1 | $ 2,098.5 | $ 1,741.9 |
| Total debt, including current portion | 1,853.0 | 1,690.7 | 1,124.8 | 1,139.2 | 742.2 |
| Inergy, L.P. partners capital | 1,146.0 | 53.3 | 40.5 | 36.9 | 50.9 |
| **Other Financial Data:** | | | | | |
| EBITDA (unaudited) | $ 347.5 | $ 299.9 | $ 296.1 | $ 225.1 | $ 282.9 |
| Adjusted EBITDA (unaudited) | 372.2 | $ 323.9 | $ 295.9 | $ 238.0 | $ 210.4 |
| Net cash provided by operating activities | 114.4 | 173.6 | 237.9 | 180.2 | 163.5 |
| Net cash used in investing activities | (390.6) | (926.4) | (230.6) | (386.7) | (187.8) |
| Net cash provided by (used in) financing activities | 143.3 | 885.5 | (13.0) | 216.0 | 20.1 |
| Maintenance capital expenditures[a] (unaudited) | 14.0 | 9.9 | 8.0 | 5.4 | 5.1 |
| **Other Operating Data (unaudited):** | | | | | |
| Retail propane gallons sold | 325.6 | 340.2 | 310.0 | 331.9 | 362.2 |
| Wholesale propane gallons delivered | 422.8 | 415.3 | 380.6 | 358.5 | 383.9 |
| **Reconciliation of Net Income to EBITDA and Adjusted EBITDA:** | | | | | |
| Net income (loss) | $ (10.6) | $ 46.4 | $ 108.1 | $ 63.1 | $ 138.6 |
| Early extinguishment of debt | 52.1 | | | | |
| Provision for income taxes | 0.7 | 0.2 | 1.7 | 1.4 | 6.5 |
| Interest expense, net | 113.5 | 91.5 | 70.5 | 62.6 | 54.4 |
| Depreciation and amortization | 191.8 | 161.8 | 115.8 | 98.0 | 83.4 |
| EBITDA | $ 347.5 | $ 299.9 | $ 296.1 | $ 225.1 | $ 282.9 |
| Non-cash (gain) loss on derivative contracts | 1.2 | (1.0) | 1.4 | 0.1 | (0.6) |
| Loss on disposal of assets | 8.2 | 11.5 | 5.2 | 11.5 | 8.0 |
| Long-term incentive and equity compensation expense | 5.8 | 10.9 | 3.1 | 3.5 | 0.7 |
| Transaction costs | 9.5 | 3.5 | | | |
| Gain on issuance of units in subsidiary | | | (8.0) | | (80.6) |
| Interest of non-controlling partners in ASC s consolidated net income | | (0.7) | (1.4) | (1.4) | |
| Interest of non-controlling partners in ASC s consolidated ITDA[b] | | (0.2) | (0.5) | (0.8) | |
| Adjusted EBITDA | $ 372.2 | $ 323.9 | $ 295.9 | $ 238.0 | $ 210.4 |

(a) Maintenance capital expenditures are defined as those capital expenditures that do not increase operating capacity or revenues from existing levels.

(b) Interest, tax, depreciation and amortization expense attributable to non-controlling partners.

(c) These amounts differ from those previously presented as a result of our adoption of FASB Accounting Standards Codification Subtopic 210-20 on October 1, 2008. In conjunction with the adoption of this standard, we elected to change our accounting policy for derivative instruments executed with the same counterparty under a master netting agreement. This change in accounting policy has been presented retroactively.

(d) These amounts have been adjusted to reflect the conversion of Holdings common units into 0.77 Inergy common units, which occurred on November 5, 2010.

(e) These amounts reflect the historical cash distributions paid per unit on the common units traded on the NYSE subsequent to March 23, 2011, and NASDAQ prior to that date, under the symbol NRGY .

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**Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.**

**Forward-Looking Statements**

This report, including information included or incorporated by reference in this report, contains forward-looking statements concerning the financial condition, results of operations, plans, objectives, future performance and business of our company and its subsidiaries. These forward-looking statements include:

- statements that are not historical in nature, but not limited to, our belief that our acquisition expertise should allow us to continue to grow through acquisitions; our belief that we will have adequate propane supply to support our retail operations; our belief that our diversification of suppliers will enable us to meet supply needs; our expectation that Inergy Midstream will complete the IPO in December 2011; our belief that the IPO will lower our cost of capital, enhance our ability to execute our growth strategy and strengthen our balance sheet; and our expectation that we will complete our development projects within budget by the anticipated in-service dates; and

- statements preceded by, followed by or that contain forward-looking terminology including the words believe, expect, may, will, should, could, anticipate, estimate, intend or the negation thereof, or similar expressions.

Forward-looking statements are not guarantees of future performance or results. They involve risks, uncertainties and assumptions. Actual results may differ materially from those contemplated by the forward-looking statements due to, among others, the following factors:

- weather conditions;

- price and availability of propane, and the capacity to transport to market areas;

- the ability to pass the wholesale cost of propane through to our customers;

- costs or difficulties related to the integration of the business of our company and its acquisition targets may be greater than expected;

- governmental legislation and regulations;

- local economic conditions;

- the demand for high deliverability natural gas storage capacity in the Northeast;

- the availability of natural gas and the price of natural gas to the consumer compared to the price of alternative and competing fuels;

- our ability to successfully implement our business plan for our natural gas storage facilities;

- labor relations;
- environmental claims;
- competition from the same and alternative energy sources;
- operating hazards and other risks incidental to transporting, storing and distributing propane;
- energy efficiency and technology trends;
- interest rates;
- the price and availability of debt and equity financing; and
- large customer defaults.

We have described under Factors That May Affect Future Results of Operations, Financial Condition or Business additional factors that could cause actual results to be materially different from those described in the forward-looking statements. Other factors that we have not identified in this report could also have this effect. You are cautioned not to put undue reliance on any forward-looking statement, which speaks only as of the date it was made.

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**General**

We are a Delaware limited partnership formed to own and operate a growing retail and wholesale propane supply, marketing and distribution business. We also own and operate a growing midstream business that includes five natural gas storage facilities (Stagecoach, Thomas Corners, Steuben, Seneca Lake and Tres Palacios), a natural gas liquids ( NGL ) storage facility (the Bath storage facility), an NGL business on the West Coast, and a solution-mining and salt production company. We further intend to pursue our growth objectives in the propane and midstream business through, among other things, future acquisitions. Our propane acquisition strategy focuses on propane companies that meet our acquisition criteria, including targeting acquisition prospects that maintain a high percentage of retail sales to residential customers, operating in attractive markets and focusing our operations under established and locally recognized trade names. Our midstream growth objectives focus both on organically expanding our existing assets and acquiring future operations that leverage our existing operating platform, produce predominantly fee-based cash flow characteristics and have future organic or commercial expansion characteristics.

Over the past several years, we have transformed our company from a propane distribution company into a diversified master limited partnership with significant investment in both the propane and midstream sectors. We continuously evaluate the best way to grow our company and unlock value for our unit holders. For example, we announced a business restructuring in August that we expect to lower our cost of capital, enhance our ability to execute our growth strategy and strengthen our balance sheet. We expect to continue to evaluate transactions that both create investor value and grow our business, as it relates to both our propane and our midstream businesses.

Both of our operating segments, propane and midstream, are supported by business development personnel groups. These groups daily responsibilities include research, sourcing, financial analysis and due diligence of potential acquisition targets and organic growth opportunities. These employees work closely with the operators of both of our segments in the course of their work to ensure the appropriate growth opportunities are pursued.

We have grown primarily through acquisitions. Since the inception of our predecessor in November 1996 through September 30, 2011, we have acquired 90 companies, including 82 retail propane companies and 8 midstream businesses, for an aggregate purchase price of approximately $2.9 billion, including working capital, assumed liabilities and acquisition costs.

On October 14, 2010, we completed our acquisition of TPGS, which owns and operates the Tres Palacios natural gas storage facility in Matagorda County, Texas. TPGS leases the surface and subsurface rights necessary to operate and expand the storage facility under an operating lease that expires on December 31, 2037, which is subject to automatic renewal for two 20-year extension periods unless TPGS elects not to extend the term of the lease. The lease payments vary based on the FERC-certificated working gas capacity of the caverns that are in service as well as an incremental payment for physical volumes of gas injected and/or withdrawn from the caverns in service. Based on our current estimates, which assumes a fourth cavern will be in service during the fourth calendar quarter of 2015, we anticipate that the contractual obligation as of September 30, 2011, to be the following (in millions, excluding the above mentioned incremental payments as future volumes are currently unknown):

| Total | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|
| $ 403.4 | $11.4 | $23.5 | $29.0 | $339.5 |

On October 19, 2010, we completed the acquisition of the propane assets of Schenck Gas Services, LLC ( Schenck ), located in East Hampton, New York. On November 15, 2010, we completed the acquisition of the propane assets of Pennington Energy Corporation ( Pennington ), headquartered in Morenci, Michigan.

On July 13, 2011, we closed on our acquisition of the Seneca Lake natural gas storage facility and two related pipelines for approximately $66.8 million from NYSEG. The natural gas storage facility and its West lateral were acquired by ASC and are subject to FERC jurisdiction. The East pipeline was acquired by Inergy Pipeline East, LLC and is subject to light-handed regulation by the NYPSC.

The purchase price allocations for these acquisitions have been prepared on a preliminary basis pending final asset valuation and asset rationalization, and changes are expected when additional information becomes available. Changes to final asset valuation of prior fiscal year acquisitions have been included in our consolidated financial statements but are not material.

The retail propane distribution business is largely seasonal due to propane s primary use as a heating source in residential and commercial buildings. As a result, cash flows from operations are generally highest from November through April when customers pay for propane purchased during the six-month peak heating season of October through March. Our propane operations generally experience net losses in the six-month off season of April through September.

Because a substantial portion of our propane is used in the weather-sensitive residential markets, the temperatures realized in our areas of operations, particularly during the six-month peak heating season of October through March, have a significant effect on our financial performance. In any given area, warmer-than-normal temperatures will tend to result in reduced propane use, while sustained colder-than-normal temperatures will tend to result in greater propane use. Therefore, we use information on normal temperatures in understanding how historical results of operations are affected by temperatures that are colder or warmer than normal and in preparing forecasts of future operations, which are based on the assumption that normal weather will prevail in each of our operating regions. Heating degree days are a general indicator of how weather impacts propane usage and are calculated for any given period by adding the difference between 65 degrees and the average temperature of each day in the period (if less than 65 degrees). While a substantial portion of our propane is used by our customers for heating needs, our propane operations are geographically diversified and not all of our propane sales are weather sensitive. Together, these factors may make it difficult to draw definitive conclusions as to the correlation of our gallon sales to weather calculations comparing weather in a year to normal or to the prior year.

The retail propane business is a margin-based business where the level of profitability is largely dependent on the difference between sales prices and product costs. Propane prices continued to be volatile during 2010 and 2011. At the main pricing hub of Mount Belvieu, Texas ( Mt. Belvieu Price ) during the fiscal year ended September 30, 2011, the average Mt. Belvieu Price was $1.42 with prices ranging from a low of $1.17 per gallon to a high of $2.29 per gallon and a price of $1.49 per gallon at September 30, 2011. Further, the average Mt. Belvieu Price in our fiscal years of 2008, 2009 and 2010 was $1.59, $0.77 and $1.12 per gallon, respectively. Our ability to pass on price increases to our customers and our hedging program has historically limited the impact that such volatility has had on our results from operations and we will continue to hedge virtually 100% of our exposure from fixed prices; however, those higher propane costs have led to higher selling prices by us and have negatively impacted our volume sales and may continue to do so in the future for reasons discussed below. While we have historically been successful in passing on any price increases to our customers, there can be no guarantees that this trend will continue in the future. In periods of increasing propane costs, we have experienced a decline in our gross profit as a percentage of revenues. In addition, during those periods we have historically experienced conservation of propane gallons used by our customers in addition to lesser gallon sales as a result of customers switching to lower price propane providers as well as alternative energy sources, all of which has resulted in a decline in gross profit. These trends generally increase in periods of sustained cost increases such as we have experienced in fiscal 2011. Further, improved technology in new appliances, including those using propane, has resulted in fewer gallons of propane used by our customers for their needs thus resulting in lesser gallon sales for us. In periods of decreasing costs, we have experienced an increase in our gross profit as a percentage of revenues. There is no assurance that because propane prices decline customers will use more propane and thus historical gallon sales declines we ve attributed to customer conservation and losses will reverse. Propane is a by-product of both crude oil refining and natural gas processing and thus typically follows the same pricing pattern as these two commodities with crude oil pricing being the more influential of the two historically. The prices of crude oil and natural gas had maintained historically high costs in calendar years 2007 and 2008 before both began to fall rather dramatically in late 2008 and throughout the 2008-2009 winter season. While natural gas pricing has remained at historically low levels since this decline, crude oil costs leveled off in the spring of 2009 before beginning another increase that persisted through both winter seasons of 2009-2010 and 2010-2011 with propane prices following a similar pattern for the majority of this time. Further, propane has been exported from the United States in greater quantities in 2011 than in the past due to higher propane costs overseas, leading to sustained higher propane costs in the United States. As such, our selling prices of propane have been at higher levels in order to attempt to maintain our historical gross margin per gallon with these higher prices negatively impacting our volume sales for the reasons discussed above. We do not attempt to predict the underlying commodity prices; however, we monitor these prices daily and adjust our operations and retail prices to maintain expected margins by passing on the wholesale costs to end users of our product. We believe that volatility in commodity prices will continue, and our ability to adjust to and manage our operations in response to this volatility may impact our operations and financial results.

We believe that the economic downturn that began in the second half of 2008 has caused certain of our retail propane customers to conserve and thereby purchase less propane and in some instances shop for lower prices that may be available from other suppliers or shop for alternative energy sources to replace some or all of their propane usage. This trend is expected to continue throughout the life of the economic downturn. In addition, although we believe the economic downturn has not currently had a material impact on our cash collections, it is possible that a prolonged economic downturn could have a negative impact on our future cash collections.

We believe our wholesale supply, marketing and distribution business complements our retail distribution business. Through our wholesale operations, we distribute propane and also offer price risk management services to propane retailers, resellers and other related businesses as well as energy marketers and dealers, through a variety of financial and other instruments, including:

- forward contracts involving the physical delivery of propane;

- swap agreements, which require payments to (or receipt of payments from) counterparties based on the differential between a fixed and variable price for propane; and

- options, futures contracts on the New York Mercantile Exchange and other contractual arrangements.

We engage in derivative transactions to reduce the effect of price volatility on our product costs and to help ensure the availability of propane during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes only when we have a matching purchase commitment from our wholesale customers. However, we may experience net unbalanced positions from time to time.

Our midstream operations primarily include the storage, transportation, processing, fractionation and sale of natural gas and NGLs and, to a lesser extent, the wholesale distribution of salt from solution mining operations of US Salt. The cash flows from these operations are predominantly fee-based under one to ten year contracts with substantial, creditworthy counterparties and, therefore, are generally economically stable and not significantly affected in the short term by changing commodity prices, seasonality or weather fluctuations.

The majority of our operating cash flows in our midstream operations are generated by our natural gas storage operations. Most of our natural gas storage revenues are based on regulated market-based tariff rates, which are driven in large part by competition and demand for our storage capacity and deliverability. Demand for storage in our key midstream market in the northeastern United States is projected to continue to be strong, driven by a shortage in storage capacity and a higher than average annual growth in natural gas demand. This demand growth is primarily driven by the natural gas-fired electric generation sector and conversion from petroleum based fuels. Demand for storage in Texas is expected to strengthen driven primarily by growth in natural gas fired generation and increasing gas supplies from growing shale developments such as the Eagle Ford shale. Demand for storage can be negatively impacted during periods in which there is a narrow seasonal spread between current and future natural gas prices. The natural gas industry is currently experiencing a significant shift in the sources of supply with prolific new shale plays primarily, and this dramatic change could affect our operations.

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We believe our midstream operations could be negatively affected in the long term by sustained downturns or sluggishness in the economy, which could affect long-term demand and market prices for natural gas and NGLs, all of which are beyond our control and could impair our ability to meet our long-term goals. However, we also believe that the contractual fee-based nature of our midstream operations may serve to mitigate this potential risk.

Traditionally, supply to our markets is satisfied primarily by production from conventional onshore and offshore production in the lower 48 states, as supplemented by production from historically declining pipeline imports from Canada, imports of LNG from foreign sources, and some Alaska production. In order to maintain current levels of U.S. natural gas supply and to meet the projected increase in demand, new sources of domestic natural gas must continue to be developed to offset an established trend of depletion associated with mature, conventional production as well as the uncertainty of future LNG imports and infrastructure challenges associated with sourcing additional production from Alaska. Over the past several years, a fundamental shift in production has emerged with the contribution of natural gas from unconventional resources (defined by the EIA as natural gas produced from shale formations and coal beds) increasing from 6% of total U.S. natural gas supply in 2000 to 16% in 2008. In fact, according to EIA data, during the three-year period from January 15, 2007 through December 15, 2010 domestic production of natural gas increased by an average of approximately 4% per annum, largely due to continued development of shale resources. The emergence of shale plays has resulted primarily from advances in horizontal drilling and hydraulic fracturing technologies, which have allowed producers to extract significant volumes of natural gas from these plays at cost-advantaged per unit economics versus most conventional plays.

We have several significant capital projects under development related to our midstream operations, including:

- the MARC I pipeline, which is a 39 mile, 30 bidirectional pipeline we propose to build in Bradford, Sullivan, and Lycoming Counties in Pennsylvania. The planned pipeline will extend between our Stagecoach south lateral interconnect with TGP s 300 Line near its compressor station 319 and Transco s Leidy Line near its compressor station 517. The MARC I pipeline is expected to have a minimum of 550,000 dekatherms per day of firm transportation capacity. We are awaiting FERC approval to construct the pipeline and currently expect to place the pipeline into service in mid-2012;

- the Watkins Glen NGL storage development project, which involves the development into NGL storage service of certain caverns acquired in the acquisition of US Salt in August 2008. Specifically, the Watkins Glen project is expected to convert certain existing caverns into 2. 1 million barrels of propane and butane storage capacity. We are awaiting NYSDEC regulatory approval to build the storage facility and currently expect to place the project into service in June 2012;

- the North/South II expansion project, which is expected to enable shippers to move natural gas bidirectionally through our Stagecoach facility from Millennium to TGP s 300 Line, and all points in between. As part of this expansion project, we intend to connect the Stagecoach north later to our Inergy East intrastate pipeline, which will further allow shippers to transport volumes from TGP s 300 Line (as well as intermediate points, including Millennium) to the point of interconnection between our Inergy East pipeline and the Dominion transmission system in Tompkins County, New York. We have not yet requested any of the regulatory approvals required to complete this expansion project; and

- the Tres Palacios header extension project, which involves laying approximately 20 miles of pipeline to connect the Tres Palacios north header system to the tailgate of Copano s Houston Central gas processing plant in Colorado County, Texas. We have not yet requested the FERC authorization required to complete this project.

As we execute on our strategic objectives, capital expansion projects will continue to be an important part of our growth plan. We have committed capital and investment expenditures at September 30, 2011, of approximately $29.9 million in our midstream operations. These capital requirements, along with the refinancings of normal maturities of existing debt, will require us to continue long-term borrowings. An inability to access capital at competitive rates could adversely affect our ability to implement our strategy. Market disruptions or a downgrade in our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more sources of liquidity. During the past several years, capital expansion projects have been exposed to cost pressures associated with the availability of skilled labor and the pricing of materials. Although certain costs have begun to decrease, there will be continual focus on project management activities to address these pressures as we move forward with planned expansion opportunities. Significant cost increases could negatively affect the returns ultimately earned on current and future expansions.

Our midstream operations in the United States are subject to regulations at the federal and state level. Regulations applicable to the gas and NGL storage industries have a significant effect on the nature of our midstream operations and the manner in which they operate. Changes to regulations are ongoing and we cannot predict the future course of changes in the regulatory environment or the ultimate effect that any future changes will have on our midstream operations.

**Recent Developments**

On August 9, 2011, we announced our intention to file a registration statement with the SEC for the IPO of a minority interest of a new master limited partnership formed to initially own and operate our Northeast natural gas and NGL midstream storage and transportation business. We intend to use all cash proceeds received in the IPO to repay indebtedness.

**Results of Operations**

**Fiscal Year Ended September 30, 2011 Compared to Fiscal Year Ended September 30, 2010**

The following table summarizes the consolidated income statement components for the fiscal years ended September 30, 2011 and 2010, respectively *(in millions)*:

| | Year Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2011 | 2010 | In Dollars | Percentage |
| Revenue | $ 2,153.8 | $ 1,786.0 | $ 367.8 | 20.6% |
| Cost of product sold | 1,476.0 | 1,165.9 | 310.1 | 26.6 |
| Gross profit (excluding depreciation and amortization) | 677.8 | 620.1 | 57.7 | 9.3 |
| Operating and administrative expenses | 323.3 | 310.7 | 12.6 | 4.1 |
| Depreciation and amortization | 191.8 | 161.8 | 30.0 | 18.5 |
| Loss on disposal of assets | 8.2 | 11.5 | (3.3) | (28.7) |
| Operating income | 154.5 | 136.1 | 18.4 | 13.5 |
| Interest expense, net | (113.5) | (91.5) | (22.0) | (24.0) |
| Early extinguishment of debt | (52.1) | | (52.1) | * |
| Other income | 1.2 | 2.0 | (0.8) | (40.0) |
| Income (loss) before income taxes | (9.9) | 46.6 | (56.5) | (121.2) |
| Provision for income taxes | 0.7 | 0.2 | 0.5 | 250.0 |
| Net income (loss) | (10.6) | 46.4 | (57.0) | (122.8) |
| Net loss attributable to non-controlling partners | 28.2 | 15.4 | 12.8 | 83.1 |
| Net income attributable to partners | $ 17.6 | $ 61.8 | $ (44.2) | (71.5)% |

* Not meaningful

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The following table summarizes revenues, including associated volume of gallons sold, for the years ended September 30, 2011 and 2010, respectively *(in millions)*:

| | Revenues | | | | Gallons | | | |
|---|---|---|---|---|---|---|---|---|
| | Year Ended September 30, | | Change | | Year Ended September 30, | | Change | |
| | 2011 | 2010 | In Dollars | Percent | 2011 | 2010 | In Units | Percent |
| Retail propane | $ 858.6 | $ 796.5 | $ 62.1 | 7.8% | 325.6 | 340.2 | (14.6) | (4.3)% |
| Wholesale propane | 603.3 | 475.9 | 127.4 | 26.8 | 422.8 | 415.3 | 7.5 | 1.8 |
| Other retail | 212.2 | 194.5 | 17.7 | 9.1 | | | | |
| Storage, fractionation and other midstream | 479.7 | 319.1 | 160.6 | 50.3 | | | | |
| Total | $ 2,153.8 | $ 1,786.0 | $ 367.8 | 20.6% | 748.4 | 755.5 | (7.1) | (0.9)% |

*Volume.* During the year ended September 30, 2011, we sold 325.6 million retail gallons of propane, a decrease of 14.6 million gallons or 4.3% from the 340.2 million retail gallons sold during fiscal 2010. Gallons sold during the year ended September 30, 2011, decreased as compared to the same prior year period as a result of lower volumes sold at our existing locations of 42.4 million, partially offset by an increase arising from acquisition volume of 27.8 million gallons. The primary cause of the declining volumes at existing locations was (1) a decline in low margin agricultural propane sold due to lesser crop drying demand in the current year period compared to prior year, (2) continued customer conservation, which we believe has resulted from the continued impact of the overall weak United States economic environment and higher propane costs, which have been at record high prices the past several years and which have increased during the fiscal period ended September 30, 2011, (3) volume declines from net customer losses primarily as a result of higher selling prices, and (4) warmer weather in our South and Southeast areas of operations. The average wholesale cost of propane has increased approximately 27% during the year ended September 30, 2011, compared to the same prior year period, continuing to impact customer buying decisions and conservation trends. Although certain of our areas of operations (South and Southeast) were warmer during the fiscal period ended September 30, 2011, compared to the same prior year period, on a consolidated retail basis, weather during the current year ended was approximately 2% colder than the prior year period and approximately 1.3% colder than normal.

Wholesale gallons delivered increased 7.5 million gallons, or 1.8%, to 422.8 million gallons in the year ended September 30, 2011, from 415.3 million gallons in the year ended September 30, 2010. The increase was due primarily to higher demand and volumes sold to existing and new customers.

The total natural gas liquid gallons sold or processed by our West Coast NGL operations decreased 14.9 million gallons, or 4.3%, to 335.0 million gallons during the year ended September 30, 2011, from 349.9 million gallons during fiscal 2010. This decrease was primarily attributable to decreased volume processed, partially offset by increased volume of natural gas liquid products sold. Both of the aforementioned changes were primarily due to local market conditions.

During the years ended September 30, 2011 and 2010, our Northeast natural gas facilities (Stagecoach, Steuben and Thomas Corners) were between 95% to 100% contracted on a firm basis, and our Bath NGL storage facility was approximately 100% contracted. As of September 30, 2011, our newly acquired Tres Palacios storage facility was approximately 71% contracted on a firm and interruptible basis and our newly acquired Seneca Lake storage facility was approximately 59% contracted on a firm basis.

*Revenues*. Revenues for the year ended September 30, 2011, were $2,153.8 million, an increase of $367.8 million, or 20.6%, from $1,786.0 million during fiscal 2010.

Revenues from retail propane sales were $858.6 million for the year ended September 30, 2011, compared to $796.5 million during fiscal 2010. This $62.1 million, or 7.8%, increase was due to a higher overall average

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selling price of propane and acquisition-related sales, which resulted in higher retail propane revenues of $91.5 million and $69.7 million, respectively. The overall average selling price of propane increased due to an increase in the wholesale cost of propane. These factors were partially offset by a $99.1 million revenue decline arising from a decrease in gallons sold to existing customers as described above.

Revenues from wholesale propane sales were $603.3 million in the year ended September 30, 2011, an increase of $127.4 million or 26.8%, from $475.9 million in the year ended September 30, 2010. This increase was driven primarily by a higher average selling price, which contributed $118.7 million to the increase and higher volumes sold, which contributed $8.7 million to the increase.

Revenues from other retail sales, which primarily includes distillates, service, rental, appliance sales and transportation services, were $212.2 million for the year ended September 30, 2011, an increase of $17.7 million, or 9.1%, from $194.5 million during fiscal 2010. Revenue from other retail sales increased as a result of higher distillate revenues of $16.7 million and an increase related to acquisitions of $3.5 million, partially offset by a $2.5 million decline in appliance, parts and other retail revenues. Distillate revenues from existing locations increased as a result of a higher comparable average selling price of distillates due to a higher wholesale cost, partially offset by lower volume sold.

Revenues from storage, fractionation and other midstream activities were $479.7 million for the year ended September 30, 2011, an increase of $160.6 million or 50.3% from $319.1 million during fiscal 2010. Revenues from our West Coast NGL operations increased $96.8 million primarily as a result of increased higher average selling prices of natural gas liquids, along with increased natural gas liquid products sold. The acquisition of our Tres Palacios gas storage facility and the commencement of Thomas Corners gas storage contracts in April 2010 increased revenues by $46.0 million and $8.1 million, respectively. Additionally revenues at our Stagecoach facility have increased $7.7 million due to interruptible wheeling service as a result of customer demand to move gas to/from our interconnecting pipes primarily due to natural gas development in Pennsylvania.

*Cost of Product Sold.* Cost of product sold for the year ended September 30, 2011, was $1,476.0 million, an increase of $310.1 million, or 26.6%, from $1,165.9 million during fiscal 2010.

Retail propane cost of product sold was $471.8 million for the year ended September 30, 2011, an increase of $58.1 million, or 14.0%, when compared to $413.7 million for fiscal 2010. This higher retail cost of product sold was driven by a $68.2 million increase arising from a higher average per gallon cost of propane and a $39.3 million increase associated with acquisition-related sales. Also contributing to a higher cost of product sold was a $2.2 million increase due to changes in non-cash charges on derivative contracts associated with retail propane fixed price sales contracts. These factors were partially offset by a $51.6 million decline in cost of product sold resulting from lower volume sales at our existing locations as discussed above.

Wholesale propane cost of product sold in the year ended September 30, 2011, was $572.2 million, an increase of $123.0 million or 27.4%, from wholesale cost of product sold of $449.2 million in the year ended September 30, 2010. This increase resulted from the higher average purchase price of propane, which contributed $114.8 million to the increase and greater volumes sold, which contributed $8.2 million.

Other retail cost of product sold was $136.3 million for the year ended September 30, 2011, compared to $113.1 million during fiscal 2010. This $23.2 million, or 20.5%, increase was primarily as a result of a $20.4 million increase in the cost for distillates, a $1.1 million increase in the cost of product sold associated with acquisition-related sales and a $1.7 million increase in the cost of other retail sales. The increase in the cost of product sold for distillates was driven by a $25.3 million increase due to a higher overall commodity cost, partially offset by a $4.9 million decline due to lower volumes sold at existing locations.

Storage, fractionation and other midstream cost of product sold was $295.7 million for the year ended September 30, 2011, an increase of $105.8 million, or 55.7%, from $189.9 million during fiscal 2010. Costs from

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our West Coast NGL operations were $94.1 million higher as a result of higher average commodity prices for natural gas liquids, along with increased natural gas liquid products sold. Additionally, the acquisition of our Tres Palacios gas storage facility resulted in a $10.0 million increase over the prior year.

Our retail and wholesale cost of product sold consists primarily of tangible products sold including all propane, distillates and other natural gas liquids sold and all propane-related appliances sold. Other costs incurred in conjunction with the distribution of these products are included in operating and administrative expenses and consist primarily of wages to delivery personnel, delivery vehicle costs consisting of fuel costs, repair and maintenance and lease expense. Costs associated with delivery vehicles approximated $74.0 million and $67.0 million for the year ended September 30, 2011 and 2010, respectively. In addition, the depreciation expense associated with the delivery vehicles and customer tanks is reported within depreciation and amortization expense and amounted to $29.4 million and $32.8 million for the year ended September 30, 2011 and 2010, respectively. Since we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of product sold, our results may not be comparable to other entities in our lines of business if they include these costs in cost of product sold.

Our storage, fractionation and other midstream cost of product sold consists primarily of commodity and transportation costs. Other costs incurred in conjunction with these services are included in operating and administrative expense and depreciation and amortization expense and consist primarily of depreciation, vehicle costs consisting of fuel costs and repair and maintenance and wages. Depreciation expense for storage, fractionation and other midstream amounted to $101.2 million and $73.6 million for the year ended September 30, 2011 and 2010, respectively. Vehicle costs and wages for personnel directly involved in providing midstream services amounted to $4.7 million and $2.9 million for the year ended September 30, 2011 and 2010, respectively. Since we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of product sold, our results may not be comparable to other entities in our lines of business if they include these costs in cost of product sold.

*Gross Profit (Excluding Depreciation and Amortization).* Gross profit for the year ended September 30, 2011, was $677.8 million, an increase of $57.7 million, or 9.3%, from $620.1 million during fiscal 2010.

Retail propane gross profit was $386.8 million for the year ended September 30, 2011, compared to $382.8 million in fiscal 2010. This $4.0 million, or 1.0%, increase was primarily driven by acquisitions and a higher cash margin per gallon, which contributed increases of $30.4 million and $23.3 million respectively. The higher cash margin per gallon was primarily due to the average selling price increasing at a greater rate than the increased cost of propane including the impact of lesser agricultural gallons sold, which generally have a lower margin. These factors were partially offset by a gross profit decline of $47.5 million attributable to lower retail gallon sales at existing locations as discussed above and a $2.2 million decline related to changes in non-cash charges on derivative contracts associated with retail propane fixed price sales contracts as discussed above.

Wholesale propane gross profit was $31.1 million in the year ended September 30, 2011, compared to $26.7 million in the year ended September 30, 2010, an increase of $4.4 million, or 16.5%. This increase resulted from higher margins obtained which contributed to $3.9 million to the increase and greater volumes sold to new and existing customers which contributed $0.5 million.

Other retail gross profit was $75.9 million for the year ended September 30, 2011, compared to $81.4 million for fiscal 2010. This $5.5 million, or 6.8%, decrease was primarily due to a $3.7 million decline in gross profit from distillates and a $4.2 million decline in other retail gross profit, partially offset by a $2.4 million increase in gross profit related to acquisitions.

Storage, fractionation and other midstream gross profit was $184.0 million in the year ended September 30, 2011, compared to $129.2 million in fiscal 2010, an increase of $54.8 million, or 42.4%. This increase was partially attributable to the gas storage acquisition of Tres Palacios, which contributed $36.0 million to the higher

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gross profit. The completion of our Thomas Corners gas storage facility in November 2009, and the relating storage contracts coming online in April 2010, also increased gross profit by approximately $7.4 million. Additionally an increase in interruptible wheeling revenues at our Stagecoach facility increased gross profit by approximately $6.0 million. Gross profit from our West Coast NGL operations was $2.7 million higher as a result of higher average margins, along with increased natural gas liquids sold to existing and new customers.

*Operating and Administrative Expenses.* Operating and administrative expenses were $323.3 million for the year ended September 30, 2011, compared to $310.7 million in fiscal 2010, an increase of $12.6 million or 4.1%. Included in the 2011 operating expenses were $9.5 million of transaction costs, primarily financing commitment expenses for the Tres Palacios acquisition, directly related to closing acquisitions during the period. The transaction costs for the same period of the prior year were $3.5 million. In addition, operating expenses increased $22.5 million due to the operations of acquisitions, partially offset by lower personnel costs from existing operations, which decreased $19.3 million, and lower insurance and other operating expenses.

*Depreciation and Amortization.* Depreciation and amortization was $191.8 million for the year ended September 30, 2011, compared to $161.8 million during fiscal 2010. This $30.0 million, or 18.5%, increase resulted primarily from acquisitions.

*Loss on Disposal of Assets.* Loss on disposal of assets decreased $3.3 million, or 28.7%, to $8.2 million in fiscal 2011 compared to $11.5 million in fiscal 2010. The losses recognized in fiscal 2011 and 2010 include losses of $11.1 million and $9.7 million, respectively, related to assets held for sale, which have been written down to their estimated selling price. In addition, we had gains in fiscal 2011 of $2.9 million and other losses in fiscal 2010 of $1.8 million. These assets, both those sold and those held for sale, consist primarily of vehicles, tanks and real estate deemed to be excess, redundant or underperforming assets. In fiscal 2011 and 2010, these assets were identified primarily as a result of losses due to disconnecting customer installations of less profitable accounts due to low margins, poor payment history or low volume usage and customers who have chosen to switch suppliers.

*Interest Expense.* Interest expense was $113.5 million for the year ended September 30, 2011, compared to $91.5 million during fiscal 2010. This $22.0 million, or 24.0%, increase was due primarily to an increase in the average outstanding borrowings during the period due to acquisitions, partially offset by a decrease in the average interest rate incurred on those borrowings. Additionally, during the year ended September 30, 2011 and 2010, we capitalized $16.2 million and $6.4 million, respectively, of interest related to certain capital improvement projects in our midstream segment as further described below in the Liquidity and Sources of Capital section.

*Early Extinguishment of Debt*. During the year ended September 30, 2011, we exercised our equity offerings redemption option in addition to a partial tender offer and redeemed 48% of our 2015 senior notes. Further, we tendered over 90% of both our 2014 and 2016 senior notes and the remaining amounts were redeemed in full. The loss associated with the above described transactions amounted to $52.1 million and was primarily related to the tender premium and the write-off of previously capitalized charges associated with the original issuance of the respective debt.

*Provision for Income Taxes.* The provision for income taxes for the year ended September 30, 2011, was $0.7 million compared to $0.2 million in fiscal 2010. The provision for income taxes for the year ended September 30, 2011, was composed of $1.2 million of current income tax expense partially offset by a $0.5 million deferred income tax benefit. The provision for income taxes for the year ended September 30, 2010, was composed of $0.5 million of current income tax expense partially offset by a $0.3 million deferred income tax benefit.

*Net Income (Loss).* Net loss was $(10.6) million for the year ended September 30, 2011, compared to net income of $46.4 million for fiscal 2010. The $57.0 million, or 122.8%, decrease in net income was primarily attributable to the charge for the early extinguishment of debt, increased depreciation and amortization, operating and administrative expenses and interest expense in the 2011 period, partially offset by higher gross profit.

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*EBITDA and Adjusted EBITDA.* The following tables summarize EBITDA and Adjusted EBITDA for the fiscal years ended September 30, 2011 and 2010, respectively (*in millions*):

| | Year Ended September 30, 2011 | 2010 |
|---|---|---|
| EBITDA: | | |
| Net income (loss) | $ (10.6) | $ 46.4 |
| Interest expense, net | 113.5 | 91.5 |
| Early extinguishment of debt | 52.1 | |
| Provision for income taxes | 0.7 | 0.2 |
| Depreciation and amortization | 191.8 | 161.8 |
| EBITDA | $ 347.5 | $ 299.9 |
| Non-cash (gain) loss on derivative contracts | 1.2 | (1.0) |
| Long-term incentive and equity compensation expense | 5.8 | 10.9 |
| Loss on disposal of assets | 8.2 | 11.5 |
| Transaction costs | 9.5 | 3.5 |
| Interest of non-controlling partners in ASC s consolidated net income | | (0.7) |
| Interest of non-controlling partners in ASC s consolidated ITDA[a] | | (0.2) |
| Adjusted EBITDA | $ 372.2 | $ 323.9 |

[a] Consists of interest, tax, depreciation and amortization expense attributable to non-controlling partners; which is determined by allocating, based on proportional ownership, the interest, taxes, depreciation and amortization of our less than wholly-owned Steuben natural gas storage facility for each period. However, we acquired 100% ownership of the Steuben natural gas storage facility during the year ended September 30, 2010.

| | Year Ended September 30, 2011 | 2010 |
|---|---|---|
| EBITDA: | | |
| Net cash provided by operating activities | $ 114.4 | $ 173.6 |
| Net changes in working capital balances | 104.1 | 60.7 |
| Non-cash early extinguishment of debt | (12.7) | |
| Provision for doubtful accounts | (3.7) | (2.8) |
| Amortization of deferred financing costs, swap premium and net bond discount | (7.4) | (7.3) |
| Unit-based compensation charges | (5.8) | (4.8) |
| Loss on disposal of assets | (8.2) | (11.5) |
| Deferred income tax | 0.5 | 0.3 |
| Interest expense, net | 113.5 | 91.5 |
| Early extinguishment of debt | 52.1 | |
| Provision for income taxes | 0.7 | 0.2 |
| EBITDA | $ 347.5 | $ 299.9 |
| Non-cash (gain) loss on derivative contracts | 1.2 | (1.0) |
| Long-term incentive and equity compensation expense | 5.8 | 10.9 |
| Loss on disposal of assets | 8.2 | 11.5 |
| Transaction costs | 9.5 | 3.5 |
| Interest of non-controlling partners in ASC s consolidated EBITDA | | (0.9) |

| | | |
|---|---|---|
| Adjusted EBITDA | $ 372.2 | $ 323.9 |

EBITDA is defined as income before income taxes, plus net interest expense and depreciation and amortization expense. For the years ended September 30, 2011 and 2010, EBITDA was $347.5 million and $299.9 million, respectively. As indicated in the table, Adjusted EBITDA represents EBITDA excluding the gain or loss on derivative contracts associated with retail propane fixed price sales contracts, the gain or loss on the disposal of assets, long-term incentive and equity compensation expenses, transaction costs, net income attributable to non-controlling partners and interest, tax, depreciation and amortization expense attributable to non-controlling partners. Transaction costs are third party professional fees and other costs that are incurred in conjunction with closing a transaction. Adjusted EBITDA was $372.2 million for fiscal 2011 compared to $323.9 million in fiscal 2010. EBITDA and Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with generally accepted accounting principles as those items are used to measure operating performance, liquidity or the ability to service debt obligations. We believe that EBITDA provides additional information for evaluating our ability to make the minimum quarterly distribution and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information for evaluating our financial performance without regard to our financing methods, capital structure and historical cost basis. Further, EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA and Adjusted EBITDA or similarly titled measures used by other corporations or partnerships.

**Fiscal Year Ended September 30, 2010 Compared to Fiscal Year Ended September 30, 2009**

The following table summarizes the consolidated income statement components for the fiscal years ended September 30, 2010 and 2009, respectively *(in millions)*:

| | Year Ended September 30, | | Change | |
|---|---|---|---|---|
| | 2010 | 2009 | In Dollars | Percentage |
| Revenue | $ 1,786.0 | $ 1,570.6 | $ 215.4 | 13.7% |
| Cost of product sold | 1,165.9 | 996.9 | 169.0 | 17.0 |
| Gross profit (excluding depreciation and amortization) | 620.1 | 573.7 | 46.4 | 8.1 |
| Operating and administrative expenses | 310.7 | 280.5 | 30.2 | 10.8 |
| Depreciation and amortization | 161.8 | 115.8 | 46.0 | 39.7 |
| Loss on disposal of assets | 11.5 | 5.2 | 6.3 | 121.2 |
| Operating income | 136.1 | 172.2 | (36.1) | (21.0) |
| Interest expense, net | (91.5) | (70.5) | (21.0) | (29.8) |
| Other income | 2.0 | 0.1 | 1.9 | 1,900.0 |
| Income before gain on issuance of units in subsidiary and income taxes | 46.6 | 101.8 | (55.2) | (54.2) |
| Gain on issuance of units in subsidiary | | 8.0 | (8.0) | * |
| Provision for income taxes | 0.2 | 1.7 | (1.5) | (88.2) |
| Net income | 46.4 | 108.1 | (61.7) | (57.1) |
| Net (income) loss attributable to non-controlling partners | 15.4 | (51.0) | 66.4 | 130.2 |
| Net income attributable to partners | $ 61.8 | $ 57.1 | $ 4.7 | 8.2% |

* not meaningful

The following table summarizes revenues, including associated volume of gallons sold, for the years ended September 30, 2010 and 2009, respectively *(in millions)*:

| | Revenues | | | | Gallons | | | |
|---|---|---|---|---|---|---|---|---|
| | Year Ended September 30, | | Change | | Year Ended September 30, | | Change | |
| | 2010 | 2009 | In Dollars | Percent | 2010 | 2009 | In Units | Percent |
| Retail propane | $ 796.5 | $ 736.7 | $ 59.8 | 8.1% | 340.2 | 310.0 | 30.2 | 9.7% |
| Wholesale propane | 475.9 | 387.7 | 88.2 | 22.7 | 415.3 | 380.6 | 34.7 | 9.1 |
| Other retail | 194.5 | 209.2 | (14.7) | (7.0) | | | | |
| Storage, fractionation and other midstream | 319.1 | 237.0 | 82.1 | 34.6 | | | | |
| Total | $ 1,786.0 | $ 1,570.6 | $ 215.4 | 13.7% | 755.5 | 690.6 | 64.9 | 9.4% |

*Volume*. During fiscal 2010, we sold 340.2 million retail gallons of propane, an increase of 30.2 million gallons or 9.7% from the 310.0 million retail gallons of propane sold during fiscal 2009. Gallons sold during fiscal 2010 increased compared to fiscal 2009 as a result of acquisition-related volume of 49.9 million gallons partially offset by a 19.7 million gallon decline from lower volumes sold at our existing locations. The primary cause of the declining volumes at existing locations was (1) continued customer conservation, which we believe has resulted from the overall weak United States economic environment and to a lesser extent the lingering effects of higher propane costs, which have been at record high prices the past several years, (2) an abrupt end to the 2009/2010 winter heating season and (3) volume declines from net customer losses. Also impacting volumes sold during fiscal 2010 compared to fiscal 2009 was the weather in certain areas of our operations. The Southern and Southeast areas of the United States were significantly colder than the prior year period; however gallon gains realized in these areas were somewhat offset by degree day losses in the Eastern and certain Northern parts of our areas of operations. In total, the weather in our areas of operations was 1% colder than normal and 2% colder than last year.

Wholesale gallons delivered increased 34.7 million gallons, or 9.1%, to 415.3 million gallons in fiscal 2010 from 380.6 million gallons in fiscal 2009. The increase was due primarily to greater volumes sold to existing customers and addition of new customers.

The total natural gas liquid gallons sold or processed by our West Coast NGL operations increased 67.3 million gallons, or 23.8%, to 349.9 million gallons in fiscal 2010 from 282.6 million gallons in fiscal 2009. This increase was primarily attributable to the Butamer addition in July 2009 and new terminalling contracts.

During fiscal 2010 and 2009, our Northeast natural gas facilities (Stagecoach, Steuben and Thomas Corners) were between 95% to 100% contracted on a firm basis, and our Bath NGL storage facility was approximately 100% contracted.

*Revenues*. Revenues in fiscal 2010 were $1,786.0 million, an increase of $215.4 million, or 13.7% from $1,570.6 million in fiscal 2009.

Revenues from retail propane sales were $796.5 million for the year ended September 30, 2010, an increase of $59.8 million, or 8.1%, compared to $736.7 million for the year ended September 30, 2009. This increase was primarily due to acquisition-related sales, which resulted in higher retail propane revenues of $117.8 million, partially offset by a combination of a decline in gallons sold to existing customers as described above and a slightly lower overall average retail selling price of propane in fiscal 2010, which contributed a revenue decline of $47.0 million and $11.0 million, respectively.

Revenues from wholesale propane sales were $475.9 million in fiscal 2010, an increase of $88.2 million or 22.7%, from $387.7 million in fiscal 2009. This increase resulted from the greater volumes of propane sold, which contributed $35.3 million to the increase in revenues and the higher average wholesale sales price of propane, which contributed $52.9 million of the increase as a result of higher product costs.

Revenues from other retail sales, which primarily include distillates, service, rental, appliance sales and transportation services, were $194.5 million in fiscal 2010, a decrease of $14.7 million, or 7.0% from $209.2 million in fiscal 2009. Revenue from other retail sales declined as a result of lower distillate revenues at existing locations of $18.3 million and a $5.5 million decline in revenues from other products and services, partially offset by a $9.1 million increase from acquisition-related sales. Distillate revenues from existing locations decreased primarily as a result of lower volumes sold. Weather in our distillate areas of operations was 6% warmer than last year and 5% warmer than normal.

Revenues from storage, fractionation and other midstream activities were $319.1 million in fiscal 2010, an increase of $82.1 million or 34.6% from $237.0 million in fiscal 2009. Revenues from our West Coast NGL operations increased $72.0 million, primarily as a result of increased commodity sales and processing fees associated with the Butamer addition. Higher average selling prices of natural gas liquids also contributed to the revenue increase. Revenues resulting from the in-servicing of our Thomas Corners facility and the related firm storage contracts resulted in a combined increase of $6.2 million. Additionally, revenues from our US Salt operations increased $3.2 million due to price increases and product mix management.

*Cost of Product Sold.* Cost of product sold for fiscal 2010 was $1,165.9 million, an increase of $169.0 million, or 17.0%, from $996.9 million in fiscal 2009.

Retail propane cost of product sold was $413.7 million for the year ended September 30, 2010, compared to $373.6 million for the year ended September 30, 2009. This $40.1 million, or 10.7%, increase was primarily due to a $68.0 million increase associated with acquisition-related volume, partially offset by a reduction of retail propane cost of product sold from existing locations of $25.5 million. The decline in retail propane cost of product sold from existing locations resulted primarily from lower volume sales as discussed above. Also contributing to the decline in retail propane cost of product sold was a $2.4 million decrease due to changes in non-cash charges on derivative contracts associated with retail propane fixed price sales contracts.

Wholesale propane cost of product sold in fiscal 2010 was $449.2 million, an increase of $85.4 million or 23.5%, from wholesale cost of product sold of $363.8 million in fiscal 2009. This increase resulted from the greater volumes of propane purchased, which contributed $33.2 million to the increase in cost and the higher average purchase price of wholesale propane sold, which contributed $52.2 million of the increase as a result of higher commodity prices.

Other retail cost of product sold was $113.1 million for the year ended September 30, 2010, compared to $124.8 million for the year ended September 30, 2009. This $11.7 million, or 9.4%, decrease was primarily due to lower costs from distillate sales at existing locations of $15.1 million and a decline in costs for other products and services of $0.9 million, partially offset by a $4.3 million increase in the cost of product sold associated with acquisition-related sales. The cost of product sold for distillates declined primarily as a result of lower volumes sold at existing locations.

Storage, fractionation and other midstream cost of product sold was $189.9 million, an increase of $55.2 million, or 41.0%, from $134.7 million in fiscal 2009. Costs from our West Coast NGL operations were $62.2 million higher primarily as a result of increased commodity sales associated with the Butamer addition. Increases in the cost of natural gas liquids also contributed to the West Coast NGL cost of products sold increase. This increase was partially offset by lower costs of storage and operational efficiencies at our Stagecoach, US Salt and Bath NGL facilities.

Our retail and wholesale cost of product sold consists primarily of tangible products sold including all propane, distillates and other natural gas liquids sold and all propane-related appliances sold. Other costs incurred in conjunction with the distribution of these products are included in operating and administrative expenses and consist primarily of wages to delivery personnel, delivery vehicle costs consisting of fuel costs, repair and maintenance and lease expense. Costs associated with delivery vehicles amounted to $67.0 million and $62.0 million for fiscal 2010 and 2009, respectively. In addition, the depreciation expense associated with the delivery vehicles and customer tanks is reported within depreciation and amortization expense and amounted to $32.8 million and $33.0 million in fiscal 2010 and 2009, respectively. Since we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of product sold, our results may not be comparable to other entities in our lines of business if they include these costs in cost of product sold.

Our storage, fractionation and other midstream cost of product sold consists primarily of commodity and transportation costs. Other costs incurred in conjunction with these services are included in operating and administrative expense and depreciation and amortization expense and consist primarily of depreciation, vehicle costs consisting of fuel costs and repair and maintenance and wages. Depreciation expense for storage, fractionation and other midstream amounted to $73.6 million and $36.9 million for fiscal 2010 and 2009, respectively. Vehicle costs combined with wages for personnel directly involved in providing midstream services amounted to $2.9 million and $2.7 million for fiscal 2010 and 2009, respectively. Since we include these costs in our operating and administrative expense and depreciation and amortization expense rather than in cost of product sold, our results may not be comparable to other entities in our lines of business if they include these costs in cost of product sold.

*Gross Profit (Excluding Depreciation and Amortization)*. Gross profit for fiscal 2010 was $620.1 million, an increase of $46.4 million, or 8.1%, from $573.7 million during fiscal 2009.

Retail propane gross profit was $382.8 million in fiscal 2010, an increase of $19.7 million, or 5.4%, compared to $363.1 million in fiscal 2009. This increase in retail propane gross profit was attributable to a $49.8 million increase from acquisitions and a $2.4 million increase related to changes in non-cash charges on derivative contracts associated with retail propane fixed price sales contracts as discussed above. These factors, which increased retail propane gross profit, were partially offset by a $23.3 million decline resulting from lower retail gallon sales at existing locations as discussed above and a $9.2 million decline arising from a lower cash margin per gallon. The decline in cash margin per gallon was primarily the result of a steep escalation in propane costs during the winter heating season contrasted with a period of falling propane costs in the prior year winter.

Wholesale propane gross profit was $26.7 million in fiscal 2010 compared to $23.9 million in fiscal 2009, an increase of $2.8 million or 11.7%. The increase in gross profit was primarily the result of both increased volumes sold and higher margins that we were able to generate from new and existing customers.

Other retail gross profit was $81.4 million for the year ended September 30, 2010, compared to $84.4 million for the year ended September 30, 2009. This $3.0 million, or 3.6%, decrease was due primarily to lower gross profit on other products and services and distillates of $4.6 million and $3.2 million, respectively, partially offset by a $4.8 million increase in related gross profit from acquisitions.

Storage, fractionation and other midstream gross profit was $129.2 million in fiscal 2010 compared to $102.3 million in fiscal 2009, an increase of $26.9 million, or 26.3%. This increase was primarily attributable to additional West Coast NGL contracts due to the Butamer addition in July 2009 and margin improvements as a result of changes in the variety of natural gas liquids sold, resulting in a $9.8 million increase. Additionally, gross profit increased $7.7 million due to the Thomas Corners facility being placed in service. Lower costs of storage and operational efficiencies at our Stagecoach, US Salt and Bath NGL facilities also contributed to the increased gross profit in fiscal 2010.

*Operating and Administrative Expenses*. Operating and administrative expenses were $310.7 million in fiscal 2010 compared to $280.5 million in fiscal 2009. This $30.2 million, or 10.8%, increase in operating expenses was due primarily to an increase in long-term incentive compensation of $7.8 million, operations of acquisitions of $29.9 million and $3.6 million of transaction expenses primarily related to those acquisitions. These types of transaction costs were capitalized in previous years, but are now required to be expensed under the new accounting rules. This increase was offset by a decrease in operating expenses of $11.1 million from other existing operations comprised predominately of lower payroll, insurance and other operating expenses.

*Depreciation and Amortization*. Depreciation and amortization increased to $161.8 million in fiscal 2010 from $115.8 million in fiscal 2009. This $46.0 million, or 39.7%, increase resulted primarily from the West Coast Butamer expansion project together with our other midstream segment projects and acquisitions.

*Loss on Disposal of Assets.* Loss on disposal of assets increased $6.3 million, or 121.2%, to $11.5 million in fiscal 2010 compared to $5.2 million in fiscal 2009. The losses recognized in fiscal 2010 and 2009 include losses of $9.7 million and $4.9 million, respectively, related to assets held for sale, which have been written down to their estimated selling price. In addition, we had other losses in fiscal 2010 and fiscal 2009 of $1.8 million and $0.3 million, respectively. These assets, both those sold and those held for sale, consist primarily of vehicles, tanks and real estate deemed to be excess, redundant or underperforming assets. In fiscal 2010 and 2009, these assets were identified primarily as a result of losses due to disconnecting customer installations of less profitable accounts due to low margins, poor payment history or low volume usage and customers who have chosen to switch suppliers.

*Interest Expense*. Interest expense increased to $91.5 million in fiscal 2010 compared to $70.5 million in fiscal 2009. This $21.0 million, or 29.8%, increase was primarily attributable to higher average interest rates incurred on our borrowings and to a lesser extent an increase in the average outstanding borrowings during the period. Additionally, during fiscal 2010 and 2009, we capitalized $6.4 million and $14.8 million, respectively, of interest related to certain capital improvement projects in our midstream segment as further described below in the Liquidity and Sources of Capital Capital Resource Activities section.

*Gain on Issuance of Units in Subsidiary.* We recorded a gain of $8.0 million in fiscal 2009, whereas no such gain was recorded in fiscal 2010.

*Provision for Income Taxes.* The provision for income taxes for fiscal 2010 was $0.2 million compared to $1.7 million for fiscal 2009. This $1.5 million, or 88.2%, decrease was due primarily to lower income earned by IPCHA. The provision for income taxes of $0.2 million in fiscal 2010 was composed of $0.5 million of current income tax expense partially offset by a $0.3 million deferred income tax benefit.

*Net Income.* Net income was $46.4 million for fiscal 2010 compared to net income of $108.1 million for fiscal 2009. The $61.7 million, or 57.1%, decrease in net income was primarily attributable to the increased interest expense and depreciation and amortization, as well as a decrease in the gain on issuance of units in subsidiary, partially offset by an increase in gross profit.

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*EBITDA and Adjusted EBITDA.* The following tables summarize EBITDA and Adjusted EBITDA for the fiscal years ended September 30, 2010 and 2009, respectively (*in millions*):

| | Year Ended September 30, 2010 | 2009 |
|---|---|---|
| EBITDA: | | |
| Net income | $ 46.4 | $ 108.1 |
| Interest expense, net | 91.5 | 70.5 |
| Provision for income taxes | 0.2 | 1.7 |
| Depreciation and amortization | 161.8 | 115.8 |
| EBITDA | $ 299.9 | $ 296.1 |
| Non-cash (gain) loss on derivative contracts | (1.0) | 1.4 |
| Long-term incentive and equity compensation expense | 10.9 | 3.1 |
| Loss on disposal of assets | 11.5 | 5.2 |
| Transaction costs | 3.5 | |
| Gain on issuance of units in subsidiary | | (8.0) |
| Interest of non-controlling partners in ASC s consolidated net income | (0.7) | (1.4) |
| Interest of non-controlling partners in ASC s consolidated ITDA[a] | (0.2) | (0.5) |
| Adjusted EBITDA | $ 323.9 | $ 295.9 |

(a) Consists of interest, tax, depreciation and amortization expense attributable to non-controlling partners; which is determined by allocating, based on proportional ownership, the interest, taxes, depreciation and amortization of our less than wholly-owned Steuben natural gas storage facility for each period. However, we acquired 100% ownership of the Steuben natural gas storage facility during the year ended September 30, 2010.

| | Year Ended September 30, 2010 | 2009 |
|---|---|---|
| EBITDA: | | |
| Net cash provided by operating activities | $ 173.6 | $ 237.9 |
| Net changes in working capital balances | 60.7 | (4.4) |
| Provision for doubtful accounts | (2.8) | (3.7) |
| Amortization of deferred financing costs, swap premium and net bond discount | (7.3) | (5.2) |
| Unit-based compensation charges | (4.8) | (3.1) |
| Loss on disposal of assets | (11.5) | (5.2) |
| Deferred income tax | 0.3 | (0.4) |
| Interest expense, net | 91.5 | 70.5 |
| Gain on issuance of units in subsidiary | | 8.0 |
| Provision for income taxes | 0.2 | 1.7 |
| EBITDA | $ 299.9 | $ 296.1 |
| Non-cash (gain) loss on derivative contracts | (1.0) | 1.4 |
| Long-term incentive and equity compensation expense | 10.9 | 3.1 |
| Loss on disposal of assets | 11.5 | 5.2 |
| Transaction costs | 3.5 | |
| Gain on issuance of units in subsidiary | | (8.0) |
| Interest of non-controlling partners in ASC s consolidated EBITDA | (0.9) | (1.9) |

| | | |
|---|---|---|
| Adjusted EBITDA | $ 323.9 | $ 295.9 |

EBITDA is defined as income before income taxes, plus net interest expense and depreciation and amortization expense. For the years ended September 30, 2010 and 2009, EBITDA was $299.9 million and $296.1 million, respectively. As indicated in the table, Adjusted EBITDA represents EBITDA excluding the gain or loss on derivative contracts associated with retail propane fixed price sales contracts, the gain or loss on the disposal of assets, long-term incentive and equity compensation expenses, transaction costs, net income attributable to non-controlling partners and interest, tax, depreciation and amortization expense attributable to non-controlling partners. Transaction costs are third party professional fees and other costs that are incurred in conjunction with closing a transaction. Adjusted EBITDA was $323.9 million for fiscal 2010 compared to $295.9 million in fiscal 2009. EBITDA and Adjusted EBITDA should not be considered an alternative to net income, income before income taxes, cash flows from operating activities, or any other measure of financial performance calculated in accordance with generally accepted accounting principles as those items are used to measure operating performance, liquidity or the ability to service debt obligations. We believe that EBITDA provides additional information for evaluating our ability to make the minimum quarterly distribution and is presented solely as a supplemental measure. We believe that Adjusted EBITDA provides additional information for evaluating our financial performance without regard to our financing methods, capital structure and historical cost basis. Further, EBITDA and Adjusted EBITDA, as we define them, may not be comparable to EBITDA and Adjusted EBITDA or similarly titled measures used by other corporations or partnerships.

**Liquidity and Sources of Capital**

**Capital Resource Activities**

On March 16, 2011, our new shelf registration statement (File No. 333-172312) was declared effective by the SEC for the periodic sale of up to $1.5 billion of common units, partnership securities and debt securities, or any combination thereof. On June 6, 2011, we issued 9,000,000 common units in a public offering. We used the net proceeds from this offering to repay borrowings under our revolving general partnership and working capital credit facilities, to fund ongoing expansion projects in our midstream business and for general partnership purposes. We have $1.176 billion remaining under this shelf registration statement.

**Cash Flows and Contractual Obligations**

Net operating cash inflows were $114.4 million and $173.6 million for the fiscal years ended September 30, 2011 and 2010, respectively. The $59.2 million decrease in operating cash flows was primarily attributable to the $39.4 million cash cost of our early extinguishment of debt. Also contributing to the decrease in operating cash flows was an increase in expenditures for inventory due primarily to an increase in commodity prices.

Net investing cash outflows were $390.6 million and $926.4 million for the fiscal years ended September 30, 2011 and 2010, respectively. Net cash outflows were primarily impacted by a $588.0 million investment in an escrow account that was utilized to fund the Tres Palacios acquisition and a $19.6 million increase in proceeds from the sale of assets. These investing cash inflows were partially offset by a $571.5 million increase in cash outlays related to acquisitions and an $88.3 million increase in capital expenditures. The increase in acquisitions was primarily related to the acquisition of Tres Palacios, and the increase in capital expenditures was primarily related to certain midstream expansion projects.

Net financing cash inflows were $143.3 million and $885.5 million for the fiscal years ended September 30, 2011 and 2010, respectively. The net change was primarily impacted by a $404.8 million decrease in proceeds related to the issuance of long-term debt, net of payments on long-term debt, a $68.8 million increase in the total distributions paid, a $291.5 million decrease in proceeds from the issuance of common units and a $3.8 million decrease in proceeds from common unit options exercised, partially offset by a $3.1 million decrease in payments for deferred financing costs and a $5.9 million increase in proceeds from swap settlement.

Net operating cash inflows were $173.6 million and $237.9 million for fiscal years ending September 30, 2010 and 2009, respectively. The $64.3 million decrease in operating cash flows was primarily attributable to decreases in cash components of net income as well as net changes in working capital balances.

Net investing cash outflows were $926.4 million and $230.6 million for the fiscal years ended September 30, 2010 and 2009, respectively. Net cash outflows were primarily impacted by a $588.0 million investment in an escrow account and a $240.9 million increase in cash outlays related to acquisitions, partially offset by a $132.5 million decrease in capital expenditures.

Net financing cash inflows (outflows) were $885.5 million and $(13.0) million for the fiscal years ending September 30, 2010 and 2009, respectively. The net change was primarily impacted by a $576.7 million increase in proceeds related to the issuance of long-term debt, net of payments on long-term debt, and a $401.5 million increase in proceeds from the issuance of Inergy common units, partially off set by a $57.5 million increase in total distributions paid, an acquisition of minority interest of $18.3 million and an $18.1 million increase in payments for deferred financing costs.

At September 30, 2011 and 2010, we had goodwill of $498.1 million and $444.3 million, respectively, representing 15% and 14% of total assets in each year, respectively. This goodwill is attributable to our acquisitions.

At September 30, 2011, we were in compliance with all debt covenants to our credit facilities.

The following table summarizes our contractual obligations as of September 30, 2011 (*in millions*):

| | Total | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|---|
| Aggregate amount of principal and interest to be paid on the outstanding long-term debt[(a)] | $ 2,720.4 | $ 122.4 | $ 235.0 | $ 675.6 | $ 1,687.4 |
| Future minimum lease payments under noncancelable operating leases | 447.5 | 23.9 | 42.9 | 37.2 | 343.5 |
| Fixed price purchase commitments[(c)] | 336.2 | 331.1 | 5.1 | | |
| Standby letters of credit | 43.5 | 35.7 | 7.8 | | |
| Purchase commitments of identified growth projects[(b)] | 29.9 | 29.9 | | | |
| Total contractual obligations | $ 3,577.5 | $ 543.0 | $ 290.8 | $ 712.8 | $ 2,030.9 |

(a) $181.2 million of our long-term debt, including interest rate swaps, is variable interest rate debt at prime rate or LIBOR plus an applicable spread. These rates plus their applicable spreads were between 2.73% and 4.75% at September 30, 2011. These rates have been applied for each period presented in the table.
(b) Identified growth projects primarily related to the North/South expansion project, the Watkins Glen NGL development project and the MARC I pipeline.
(c) Fixed price purchase commitments are offset by sales contracts that are included in our cash flow hedging program and the remainder are offset volumetrically with fixed price sale contracts.

We believe that anticipated cash from operations and borrowing capacity under our Credit Agreement described below will be sufficient to meet our liquidity needs for the foreseeable future. If our plans or assumptions change or are inaccurate, or we make acquisitions, we may need to raise additional capital. While global financial markets and economic conditions have been disrupted and volatile in the past, the conditions have improved more recently. However, we give no assurance that we can raise additional capital to meet these needs. We have identified capital expansion project opportunities in our midstream operations. As of September 30, 2011, we have firm purchase commitments totaling approximately $29.9 million related to certain of these projects. Additional commitments or expenditures, if any, we may make toward any one or more of these projects are at the discretion of the Partnership. Any discontinuation of the construction of these projects will likely result in less future cash flow and earnings than we have previously indicated.

**Description of Credit Facility**

On November 24, 2009, we entered into a secured credit facility ( Credit Agreement ) which provided borrowing capacity of up to $525 million in the form of a $450 million revolving general partnership credit facility ( General Partnership Facility ) and a $75 million working capital credit facility ( Working Capital Facility ). This facility was to mature on November 22, 2013. Borrowings under these secured facilities are available for working capital needs, future acquisitions, capital expenditures and other general partnership purposes, including the refinancing of existing indebtedness under the former credit facility.

On February 2, 2011, we amended and restated the Credit Agreement to add a $300 million term loan facility (the Term Loan Facility ). The Term Loan Facility matures on February 2, 2015, and bears interest, at our option, subject to certain limitations, at a rate equal to the following:

- the Alternate Base Rate, which is defined as the higher of (i) the federal funds rate plus 0.50%; (ii) JP Morgan s prime rate; or (iii) the Adjusted LIBO Rate plus 1%; plus a margin varying from 1.00% to 2.25%; or

- the Adjusted LIBO Rate, which is defined as the LIBO Rate plus a margin varying from 2.00% to 3.25%.

On July 28, 2011, we further amended our amended and restated Credit Agreement to (i) raise the aggregate revolving commitment from $525 million to $700 million ( Revolving Loan Facility ) with that amount existing as a singular tranche, (ii) reduce the applicable rate on revolving loans and commitment fees, (iii) modify and refresh certain covenants and covenant baskets, and (iv) extend the maturity date from November 22, 2013 to July 28, 2016.

The Credit Agreement contains various affirmative and negative covenants and default provisions, as well as requirements with respect to the maintenance of specified financial ratios and limitations on making investments, permitting liens and entering into other debt obligations. All borrowings under the Revolving Loan Facility bear interest, at our option, subject to certain limitations, at a rate equal to the following:

- the Alternate Base Rate, which is defined as the higher of (i) the federal funds rate plus 0.50%; (ii) JP Morgan s prime rate; or (iii) the Adjusted LIBO Rate plus 1%; plus a margin varying from 0.75% to 2.00%; or

- the Adjusted LIBO Rate, which is defined as the LIBO Rate plus a margin varying from 1.75% to 3.00%.

At September 30, 2011, the balance outstanding under the Credit Agreement was $381.2 million, of which $300.0 million was borrowed under the Term Loan Facility and $81.2 million under the Revolving Loan Facility. At September 30, 2010, there was no balance outstanding under the Credit Agreement. The interest rates of the Revolving Loan Facility are based on prime rate and LIBOR plus the applicable spreads, resulting in interest rates which were between 2.73% and 4.75% at September 30, 2011. The interest rate on the Term Loan Facility is based on LIBOR plus the applicable spread, resulting in an interest rate that was 3.23% at September 30, 2011. Availability under the Credit Agreement amounted to $575.3 million and $505.3 million at September 30, 2011 and 2010, respectively. Outstanding standby letters of credit under the Credit Agreement amounted to $43.5 million and $19.7 million at September 30, 2011 and 2010, respectively.

During each fiscal year beginning October 1, the outstanding balance of the Working Capital Facility must be reduced to $10.0 million or less for a minimum of 30 consecutive days during the period commencing March 1 and ending September 30 of each calendar year. This requirement was removed in the July 28, 2011 amendment with the Revolving Loan Facility now existing as a singular tranche facility.

We are required to use 50% of the net cash proceeds (that are not applied to purchase replacement assets) from asset dispositions (other than the sale of inventory and motor vehicles in the ordinary course of business, sales of

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assets among us and our domestic subsidiaries and the sale or disposition of obsolete or worn-out equipment) to reduce borrowings under the Credit Agreement during any fiscal year in which unapplied net cash proceeds are in excess of $50 million.

In addition, the Credit Agreement contains various covenants limiting our ability to (subject to various exceptions), among other things:

- grant or incur liens;
- incur other indebtedness (other than permitted debt as defined in the Credit Agreement);
- make investments, loans and acquisitions;
- enter into a merger, consolidation or sale of assets;
- enter into any sale-leaseback transaction or enter into any new business;
- enter into any agreement that conflicts with the credit facility or ancillary agreements;
- make any change in its principles and methods of accounting as currently in effect, except as such changes are permitted by GAAP;
- enter into certain affiliate transactions;
- pay dividends or make distributions if we are in default under the Credit Agreement or in excess of available cash;
- permit operating lease obligations to exceed $50 million in any fiscal year;
- enter into any debt (other than permitted junior debt) that contains covenants more restrictive than those of the Credit Agreement or enter into any permitted junior debt that contains negative covenants more restrictive than those of the Credit Agreement;
- enter into hedge agreements that do not hedge or mitigate risks to which we have actual exposure;
- enter into put agreements granting put rights with respect to equity interests of us or our subsidiaries;
- prepay, redeem, defease or otherwise acquire any permitted junior debt or make certain amendments to permitted junior debt; and
- modify organizational documents.

Permitted junior debt consists of:

- our $95 million 8.75% senior notes due March 1, 2015 that were issued on February 2, 2009;
- our $600 million 7.00% senior notes due October 1, 2018 that were issued on September 27, 2010;
- our $750 million 6.875% senior notes due August 1, 2021 that were issued on January 19, 2011;
- other debt that is substantially similar to the 6.875% senior notes; and
- other debt of ours and our subsidiaries that is either unsecured debt, or second lien debt that is subordinated to the obligations under the Credit Agreement.

Permitted junior debt may be incurred under the Credit Agreement so long as:

- there is no default under the Credit Agreement;
- the ratio of our total funded debt to consolidated EBITDA for the four fiscal quarters most recently ended must be no greater than 5.25 to 1.0;
- the debt does not mature, and no installments of principal are due and payable on the debt, prior to the maturity date of the Credit Agreement; and

- other than in connection with the 8.75%, 7.00% and 6.875% senior notes and other substantially similar debt, the debt does not contain covenants more restrictive than those in the Credit Agreement.

The Credit Agreement contains the following financial covenants:

- the ratio of our total funded debt (as defined in the Credit Agreement) to consolidated EBITDA (as defined in the Credit Agreement) for the four fiscal quarters most recently ended must be no greater than 5.25 to 1.0;
- the ratio of our senior secured funded debt (as defined in the Credit Agreement) to consolidated EBITDA (as defined in the Credit Agreement) for the four fiscal quarters most recently ended must be no greater than 3.50 to 1.0; and
- the ratio of our consolidated EBITDA to consolidated interest expense (as defined in the Credit Agreement), for the four fiscal quarters then most recently ended, must not be less than 2.5 to 1.0.

At September 30, 2011, our ratio of total funded debt to consolidated EBITDA was 4.61 to 1.0, and our ratio of consolidated EBITDA to consolidated interest expense was 3.73 to 1.0.

Each of the following is an event of default under the Credit Agreement:

- default in payment of principal when due;
- default in payment of interest, fees or other amounts within three days of their due date;
- violation of specified affirmative and negative covenants;
- default in performance or observance of any term, covenant, condition or agreement contained in the Credit Agreement or any ancillary document related to the credit facility for 30 days;
- specified cross-defaults;
- bankruptcy and other insolvency events of us or our material subsidiaries;
- impairment of the enforceability or the validity of agreements relating to the Credit Agreement;
- judgments exceeding $10 million (to the extent not covered by insurance) against us or any of our subsidiaries are undischarged or unstayed for 45 consecutive days;
- certain defaults under ERISA that could reasonably be expected to result in a material adverse effect on us; or

the occurrence of certain change of control events with respect to us.

**Senior Unsecured Notes**

**2014 Senior Notes**

In February and March 2011, $394.5 million in aggregate principal of the 2014 Senior Notes were tendered and the remaining $30.5 million were redeemed. There was no balance remaining on the 2014 Senior Notes at September 30, 2011.

**2016 Senior Notes**

In February and March 2011, $370.0 million in aggregate principal of the 2016 Senior Notes were tendered and the remaining $30.0 million were redeemed. There was no balance remaining on the 2016 Senior Notes at September 30, 2011.

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**2015 Senior Notes**

On February 2, 2009, we and our wholly-owned subsidiary, Inergy Finance Corp, issued $225 million aggregate principal amount of 8.75% senior unsecured notes due 2015 (the 2015 Senior Notes ) under Rule 144A to eligible purchasers. The 8.75% notes mature on March 1, 2015, and were issued at 90.191% of the principle amount to yield 11%.

The 2015 Senior Notes contain covenants similar to the 2014 and 2016 Senior Notes. We used the net proceeds of the offering to repay outstanding indebtedness under the General Partnership Facility. The 2015 Senior Notes represent senior unsecured obligations of our and rank *pari passu* in right of payment with all other present and future senior indebtedness of ours. The 2015 Senior Notes are fully, unconditionally, jointly and severally guaranteed by our wholly-owned domestic subsidiaries.

On October 7, 2009, we completed an offer to exchange our existing 8.75% 2015 Senior Notes for $225 million of 8.75% senior notes due 2015 (the 2015 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2015 Exchange Notes did not provide us with any additional proceeds and satisfied our obligations under the registration rights agreement.

The 2015 Senior Notes are redeemable, at our option, in whole or in part, at any time on or after March 1, 2013, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| Year | Percentage |
|---|---|
| 2013 | 104.375% |
| 2014 and thereafter | 100.000% |

During the year ended September 30, 2011, $78.8 million in aggregate principal of these notes were redeemed utilizing the equity redemption feature of the indenture, an additional aggregate principal amount of $30.2 million was redeemed through tender and an additional aggregate principal amount of $21.0 million through purchases on the open markets.

**2018 Senior Notes**

On September 27, 2010, we and our wholly-owned subsidiary, Inergy Finance Corp, issued $600 million aggregate principal amount of 7% senior unsecured notes due 2018 (the 2018 Senior Notes ) under Rule 144A to eligible purchasers. The 2018 Senior Notes mature on October 1, 2018.

The 2018 Senior Notes contain covenants similar to the existing senior 2015 Senior Notes. We used the net proceeds of the offering to fund part of the consideration for the Tres Palacios acquisition. The 2018 Senior Notes represent senior unsecured obligations of ours and rank *pari passu* in right of payment with all other present and future senior indebtedness of ours. The 2018 Senior Notes are fully, unconditionally, jointly and severally guaranteed by our wholly-owned domestic subsidiaries.

On June 2, 2011, we completed an offer to exchange our existing 7% 2018 Senior Notes for $600 million of 7% senior notes due 2018 (the 2018 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2018 Exchange Notes did not provide us with any additional proceeds and satisfied our obligations under the registration rights agreement.

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The 2018 Senior Notes are redeemable, at our option, in whole or in part, at any time on or after October 1, 2014, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| Year | Percentage |
|---|---|
| 2014 | 103.500% |
| 2015 | 101.750% |
| 2016 and thereafter | 100.000% |

**2021 Senior Notes**

On January 19, 2011, we and our wholly-owned subsidiary, Inergy Finance Corp, issued $750 million aggregate principal amount of 6.875% senior unsecured notes due 2021 (the 2021 Senior Notes ) under Rule 144A to eligible purchasers. The 2021 Senior Notes mature on August 1, 2021.

The 2021 Senior Notes contain covenants similar to the existing senior unsecured notes due 2015 and 2018. The 2021 Senior Notes represent senior unsecured obligations of Inergy and rank *pari passu* in right of payment with all other present and future senior indebtedness of ours. The 2021 Senior Notes are fully, unconditionally, jointly and severally guaranteed by our wholly-owned domestic subsidiaries.

On September 28, 2011, we completed an offer to exchange our existing 2021 Senior Notes for $750 million of 6.875% senior notes due 2021 (the 2021 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2021 Exchange Notes did not provide us with any additional proceeds and satisfied our obligations under the registration rights agreement.

The 2021 Senior Notes are redeemable, at our option, in whole or in part, at any time on or after August 1, 2016, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| Year | Percentage |
|---|---|
| 2016 | 103.438% |
| 2017 | 102.292% |
| 2018 | 101.146% |
| 2019 and thereafter | 100.000% |

We used the net proceeds from the 2021 Senior Notes and the Term Loan Facility to: (1) fund the partial redemption of our 2015 Senior Notes; (2) fund our tender offers for portions of our 2014 Senior Notes, 2015 Senior Notes and 2016 Senior Notes; and (3) redeem all 2014 Senior Notes and 2016 Senior Notes not acquired in the tender offers related to such notes. The remaining net proceeds were used to repay outstanding borrowings under the General Partnership Facility and the Working Capital Facility and to provide additional working capital for general partnership purposes.

The indentures governing our senior unsecured notes discussed above are substantially similar and contain covenants that, among other things, will limit our ability and the ability of our restricted subsidiaries to:

sell assets;

pay distributions on, redeem or repurchase our units or redeem or repurchase our subordinated debt;

make investments;

incur or guarantee additional indebtedness or issue preferred units;

create or incur certain liens;

- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

These covenants are subject to important exceptions and qualifications, and if the notes achieve an investment grade rating from either Moody s or Standard & Poor s, many of these covenants will terminate.

In addition, the indentures governing our senior notes restrict our ability to pay cash distributions. Before we can pay a distribution to our unitholders, we must demonstrate that the fixed charge coverage ratio (as defined in the senior notes indentures) is at least 1.75 to 1.0.

**Recent Accounting Pronouncements**

In June 2011 the FASB issued Accounting Standards Update No. 2011-05, Presentation of Comprehensive Income ( ASU 2011-05 ). Under ASU 2011-05, an entity has the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Under both options, an entity will be required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. Furthermore, regardless of the presentation methodology elected, the entity will be required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income. The amendments contained in ASU 2011-05 do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. The amendments also do not affect how earnings per share is calculated or presented. ASU 2011-05 is effective for us on October 1, 2012. We do not currently anticipate the adoption of ASU 2011-05 will impact comprehensive income, however it will require us to change our historical practice of showing these items within the Consolidated Statement of Partners Capital.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, Improving Disclosures about Fair Value Measurements ( ASU 2010-06 ), which is included in the ASC Topic 820 (Fair Value Measurements and Disclosures). ASU 2010-06 requires new disclosures on the amount and reason for transfers in and out of Level 1 and Level 2 fair value measurements. ASU 2010-06 also requires disclosure of activities, including purchases, sales, issuances and settlements within the Level 3 fair value measurements and clarifies existing disclosure requirements on levels of disaggregation and disclosures about inputs and valuation techniques. We have previously adopted the new disclosures on the reason for transfers in and out of Level 1 and Level 2. The new disclosures for Level 3 are effective for fiscal years beginning after December 15, 2010. We do not currently anticipate that the adoption of the Level 3 disclosure requirements of ASU 2010-06 will result in a material change to the financial statements.

**Critical Accounting Policies**

*Accounting for Price Risk Management.* We utilize certain derivative financial instruments to (i) manage our exposure to commodity price risk, specifically, the related change in the fair value of inventories, as well as the variability of cash flows related to forecasted transactions; (ii) ensure adequate physical supply of commodity will be available; and (iii) manage our exposure to interest rate risk associated with fixed rate senior notes and our floating rate term loan. We record all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of these derivative financial instruments are recorded either through current earnings or as other comprehensive income, depending on the type of transaction.

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We determine fair value of our derivative financial instruments according to the following hierarchy: (1) comparable market prices to the extent available; (2) internal valuation models that utilize market data (observable inputs) as input variables; and lastly, (3) internal valuation models that use management s assumptions about the assumptions that market participants would use in pricing the instruments (unobservable inputs) to the extent (1) and (2) are unavailable. Because the majority of the instruments we enter into are traded in liquid markets, we value these instruments based on prices indicative of exiting the position. As a consequence, the majority of the values of our derivative financial instruments are based upon actual prices of like kind trades that are obtained from on-line trading systems and verified with broker quotes. Changes in the fair value of these derivative financial instruments, primarily resulting from variability in supply and demand, are recorded either through current earnings or as other comprehensive income, depending on the type of transaction.

On the date the derivative contract is entered into, we generally designate specific derivatives as either a hedge of the fair value of a recognized asset or liability (fair value hedge), or a hedge of a forecasted transaction (cash flow hedge). We document all relationships between hedging instruments and hedged items, as well as our risk-management objective and strategy for undertaking various hedge transactions. We use regression analysis or the dollar offset method to assess, both at the hedge s inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair value or cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that is has ceased to be a highly effective hedge, we discontinue hedge accounting prospectively. When hedge accounting is discontinued because it is determined that the derivative no longer qualifies as an effective hedge, we continue to carry the derivative on the balance sheet at fair value, and recognize changes in the fair value of the derivative through current-period earnings.

We are party to certain commodity derivative financial instruments that are designated as hedges of selected inventory positions, and qualify as fair value hedges. We are also periodically party to certain interest rate swap agreements designed to manage interest rate risk exposure. Our overall objective for entering into fair value hedges is to manage our exposure to fluctuations in commodity prices and changes in the fair market value of our inventories and fixed rate borrowings. The commodity derivatives are recorded at fair value on the balance sheet as price risk management assets or liabilities and the related change in fair value is recorded to earnings in the current period as cost of product sold. The interest rate derivatives are recorded at fair value on the balance sheets in other assets or liabilities and the related change in fair value is recorded to earnings in the current period as interest expense.

Any ineffective portion of the fair value hedges is recognized as cost of product sold in the current period. We recognized a \$1.8 million, \$0.4 million and \$0.2 million net gain in the years ended September 30, 2011, 2010 and 2009, respectively, related to the ineffective portion of our fair value hedging instruments. In addition, for the year ended September 30, 2011, we recognized no gain, and for the years ended September 30, 2010 and 2009, we recognized a net loss of \$0.1 million related to the portion of fair value hedging instruments that we excluded from our assessment of hedge effectiveness.

We also enter into derivative financial instruments that qualify as cash flow hedges, which hedge the exposure of variability in expected future cash flows predominantly attributable to forecasted purchases to supply fixed price sale contracts and forecasted interest payments on our Term Loan Facility. These derivatives are recorded on the balance sheet at fair value as price risk management assets or liabilities. The effective portion of the gain or loss on these cash flow hedges is recorded in other comprehensive income in partner s capital and reclassified into earnings in the same period in which the hedge transaction affects earnings. In certain situations under the rules, the ineffective portion of the gain or loss is recognized as cost of product sold in the current period. Accumulated other comprehensive income (loss) was \$(6.7) million and \$4.4 million at September 30, 2011 and 2010, respectively. Included in accumulated other comprehensive income (loss) was \$(2.4) million attributable to commodity instruments and \$(4.3) million attributable to interest rate swaps. Approximately \$(2.0) million is expected to be reclassified to earnings from other comprehensive income over the next twelve months.

Our policy is to offset fair value amounts of derivative instruments and cash collateral paid or received with the same counterparty under a master netting arrangement.

The cash flow impact of derivative financial instruments is reflected as cash flows from operating activities in the consolidated statements of cash flows.

If management s assumptions related to unobservable inputs used in the pricing models for our financial instruments, which include forwards, futures and options, are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains. A hypothetical 10% difference in the assumptions made for our unobservable inputs would have impacted our estimated fair value of these derivatives at September 30, 2011, and would have affected net income by $0.1 million for the year ended September 30, 2011.

*Revenue Recognition*. Sales of propane, other liquids and salt are recognized at the time product is shipped or delivered to the customer depending on the sales terms. Gas processing and fractionation fees are recognized upon delivery of the product. Revenue from the sale of propane appliances and equipment is recognized at the later of the time of sale or installation. Revenue from repairs and maintenance is recognized upon completion of the service. Revenue from storage contracts is recognized during the period in which storage services are provided.

*Impairment of Goodwill and Long-Lived Assets.* Goodwill is subject to at least an annual assessment for impairment by applying a fair-value-based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

We completed the valuation of each of our reporting units and determined no impairment existed as of September 30, 2011. The valuation of our reporting units requires us to make certain assumptions as it relates to future operating performance. When considering operating performance, various factors are considered such as current and changing economic conditions and the commodity price environment, among others. If the growth assumptions embodied in the current year impairment testing prove inaccurate, we could incur an impairment charge. A 10% decrease in the estimated future cash flows and a 1% increase in the discount rate used in our impairment analysis would not have indicated a potential impairment of any of our intangible assets.

The value of the assets to be disposed of is estimated at the date a commitment to dispose the asset is made. Our estimate of any loss associated with an asset sale is dependent on certain assumptions we make with respect to the net realizable value of the particular asset. A 10% decrease in the estimated net realizable value would have resulted in an additional loss of $0.6 million at September 30, 2011.

*Self-Insurance.* We are insured by third parties, subject to varying retention levels of self-insurance, which management considers prudent. Such self-insurance relates to losses and liabilities primarily associated with medical claims, workers compensation claims and general, product, vehicle and environmental liability. Losses are accrued based upon management s estimates of the aggregate liability for claims incurred using certain assumptions followed in the insurance industry and based on past experience. The primary assumption utilized is actuarially determined loss development factors. The loss development factors are based primarily on historical data. Our self insurance reserves could be affected if future claims development differs from the historical trends. We believe changes in health care costs, trends in health care claims of our employee base, accident frequency and severity and other factors could materially affect the estimate for these liabilities. We continually monitor changes in employee demographics, incident and claim type and evaluate our insurance accruals and adjust our accruals based on our evaluation of these qualitative data points. At September 30, 2011 and 2010, our self-insurance reserves were $20.6 million and $19.3 million, respectively. We estimate that $14.1 million of this balance will be paid subsequent to September 30, 2012. As such, $14.1 million has been classified in other long-term liabilities on the consolidated balance sheets.

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**Factors That May Affect Future Results of Operations, Financial Condition or Business**

We may not be able to generate sufficient cash from operations to allow us to pay the minimum quarterly distribution.

Our future acquisitions and completion of our expansion projects will require significant amounts of debt and equity financing, which may not be available to us on acceptable terms, or at all.

Since weather conditions may adversely affect the demand for propane, our financial condition and results of operations are vulnerable to, and will be adversely affected by, warm winters.

If we do not continue to make acquisitions on economically acceptable terms, our future financial performance will be reliant upon internal growth and efficiencies.

We cannot assure you that we will be successful in integrating our recent acquisitions.

Sudden and sharp propane price increases that cannot be passed on to retail customers may adversely affect our profit margins.

Our indebtedness may limit our ability to borrow additional funds, make distributions to unitholders or capitalize on acquisition or other business opportunities.

The highly competitive nature of the retail propane business could cause us to lose customers, thereby reducing our revenues.

If we are not able to purchase propane from our principal suppliers, our results of operations would be adversely affected.

If our midstream business is not able to renew or replace expiring contracts, our results of operations would be adversely affected.

Competition from alternative energy sources may cause us to lose customers, thereby reducing our revenues.

Our business would be adversely affected if service at our principal storage facilities or on the common carrier pipelines we use is interrupted.

We are subject to operating and litigation risks that could adversely affect our operating results to the extent not covered by insurance.

Our results of operations and financial condition, particularly those of our midstream business, may be adversely affected by governmental regulation and associated environmental regulatory costs.

Energy efficiency and new technology may reduce the demand for propane.

Due to our lack of asset diversification, adverse developments in our propane business would reduce our ability to make distributions to our unitholders.

See Item 1A Risk Factors for further discussion of factors that could impact our business.

**Item 7A. Quantitative and Qualitative Disclosures About Market Risk.**

**Interest Rate Risk**

We have a term loan and a revolving line of credit subject to the risk of loss associated with movements in interest rates. At September 30, 2011, we had floating rate obligations totaling $181.2 million borrowed under our Term Loan Facility (net of certain interest rate swaps, which convert our floating rate term loan to a fixed rate with a notional amount of $225 million), Revolving Loan Facility and one interest rate swap with a notional amount of $25 million that converts a portion of our fixed rate senior notes to floating. Floating rate obligations expose us to the risk of increased interest expense in the event of increases in short-term interest rates.

During fiscal 2011, we entered into eleven interest rate swaps with an aggregate notional amount of $275 million. One was scheduled to mature in 2015 and the remaining ten were scheduled to mature in 2018. In August 2011, our ten interest rate swaps maturing in 2018 were terminated and we received approximately $14.3 million in proceeds. These swaps had an aggregate notional amount of $250 million.

If the floating rate were to fluctuate by 100 basis points from September 2011 levels, our interest expense would change by a total of approximately $1.8 million per year.

**Commodity Price, Market and Credit Risk**

Inherent in our contractual portfolio are certain business risks, including market risk and credit risk. Market risk is the risk that the value of the portfolio will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. We take an active role in managing and controlling market and credit risk and have established control procedures, which are reviewed on an ongoing basis. We monitor market risk through a variety of techniques, including daily reporting of the portfolio s position to senior management. We attempt to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with assets from price risk management activities as of September 30, 2011 and 2010, were propane retailers, resellers, energy marketers and dealers.

The propane industry is a margin-based business in which gross profits depend on the excess of sales prices over supply costs. As a result, our profitability will be sensitive to changes in wholesale prices of propane caused by changes in supply or other market conditions. When there are sudden and sharp increases in the wholesale cost of propane, we may not be able to pass on these increases to our customers through retail or wholesale prices. Propane is a commodity and the price we pay for it can fluctuate significantly in response to supply or other market conditions. We have no control over supply or market conditions. In addition, the timing of cost pass-throughs can significantly affect margins. Sudden and extended wholesale price increases could reduce our gross profits and could, if continued over an extended period of time, reduce demand by encouraging our retail customers to conserve or convert to alternative energy sources.

We engage in hedging and risk management transactions, including various types of forward contracts, options, swaps and futures contracts, to reduce the effect of price volatility on our product costs, protect the value of our inventory positions and to help ensure the availability of propane during periods of short supply. We attempt to balance our contractual portfolio by purchasing volumes only when we have a matching purchase commitment from our wholesale customers. However, we may experience net unbalanced positions from time to time, which we believe to be immaterial in amount. In addition to our ongoing policy to maintain a balanced position, for accounting purposes we are required, on an ongoing basis, to track and report the market value of our derivative portfolio.

*Fair Value*

The fair value of the derivatives and inventory exchange contracts related to price risk management activities as of September 30, 2011, and September 30, 2010, was assets of $17.1 million and $22.5 million, respectively and liabilities of $19.0 million and $24.3 million, respectively.

We use observable market values for determining the fair value of our trading instruments. In cases where actively quoted prices are not available, other external sources are used which incorporate information about commodity prices in actively quoted markets, quoted prices in less active markets and other market fundamental analysis. Our risk management department regularly compares valuations to independent sources and models on a quarterly basis.

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**Sensitivity Analysis**

A theoretical change of 10% in the underlying commodity value would result in a $0.3 million change in the market value of the contracts as there were 1.8 million gallons of net unbalanced positions at September 30, 2011.

**Item 8. Financial Statements and Supplementary Data.**

Reference is made to the financial statements and report of independent registered public accounting firm included later in this report under Item 15.

**Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.**

None.

**Item 9A. Controls and Procedures.**

We maintain controls and procedures designed to provide a reasonable assurance that information required to be disclosed in our reports that we file or submit under the Securities Exchange Act of 1934 are recorded, processed, summarized and reported within the time periods specified by the rules and forms of the SEC, and that information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. An evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as such terms are defined in Rule 13a-15(e) and 15d-15(e) of the Exchange Act). Based upon that evaluation, management, including the Chief Executive Officer and the Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2011, at the reasonable assurance level. There have been no changes in our internal control over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the period ended September 30, 2011, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

**Changes in Internal Control over Financial Reporting**

In fiscal 2011, we completed the acquisitions of Tres Palacios, Schenck and Pennington. See Note 3 Acquisitions for a discussion of the acquisitions and related financial data.

We are currently in the process of evaluating the internal controls and procedures of our current acquisitions. Further, we are in the process of integrating their operations. Management will continue to evaluate our internal control over financial reporting as we execute integration activities, however, integration activities could materially affect our internal control over financial reporting in future periods.

**Management s Report on Internal Control Over Financial Reporting**

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, pursuant to Exchange Act Rules 13a-15(f). Our internal control system was designed to provide reasonable assurance to management and our board of directors regarding the preparation and fair presentation of published financial statements in accordance with generally accepted accounting principles.

Management recognizes that there are inherent limitations in the effectiveness of any system of internal control, and accordingly, even effective internal control can provide only reasonable assurance with respect to financial statement preparation and fair presentation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.

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Management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the operations resulting from the fiscal 2011 acquisitions (collectively the Acquisitions ), which are included in the 2011 consolidated financial statements. The financial reporting systems of the Acquisitions were integrated into the Company s financial reporting systems throughout 2011. Therefore, the Company did not have the practical ability to perform an assessment of their internal controls in time for this current year-end. The Company fully expects to include the Acquisitions in next year s assessment. The Acquisitions constituted $110.2 million and $72.4 million in total assets and revenues, respectively, in the consolidated financial statements.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of the Company s internal control over financial reporting as of September 30, 2011. In making this assessment, we used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based upon our assessment, we conclude that, as of September 30, 2011, our internal control over financial reporting is effective, in all material respects, based upon those criteria.

Our independent registered public accounting firm, Ernst & Young LLP, issued an attestation report dated November 15, 2011, on the effectiveness of our internal control over financial reporting, which is included herein.

**Item 9B. Other Information.**

None.

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## PART III

### Item 10. Directors, Executive Officers and Corporate Governance.

### Our General Partner Manages Inergy, L.P.

Inergy GP, LLC, our general partner, manages our operations and activities. Our general partner is not elected by our unitholders and will not be subject to re-election on a regular basis in the future. Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 $^{2}/_{3}$% of the outstanding units, including units held by the general partners and their affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of the general partner is also subject to the approval of a successor general partner by the vote of the holders of a majority of the outstanding common units. Unitholders do not directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to the unitholders. Our general partner is liable, as a general partner, for all of our debts (to the extent not paid from our assets), except for specific nonrecourse indebtedness or other obligations. Whenever possible, our general partner intends to incur indebtedness or other obligations that are nonrecourse.

As is commonly the case with publicly-traded limited partnerships, we are managed and operated by the officers of our general partner and are subject to the oversight of the directors of our general partner. The board of directors of our general partner is presently composed of six directors.

### Directors and Executive Officers

The following table sets forth certain information with respect to the executive officers and members of the board of directors of our general partner. Executive officers and directors will serve until their successors are duly appointed or elected.

| Executive Officers and Directors | Age | Position with our General Partner |
|---|---|---|
| John J. Sherman | 56 | President, Chief Executive Officer and Director |
| Phillip L. Elbert | 53 | President and Chief Operating Officer Propane Operations and Director |
| R. Brooks Sherman, Jr. | 46 | Executive Vice President and Chief Financial Officer |
| Carl A. Hughes | 57 | Senior Vice President Business Development |
| Laura L. Ozenberger | 53 | Senior Vice President General Counsel and Secretary |
| William R. Moler | 45 | Senior Vice President Natural Gas Midstream Operations |
| Warren H. Gfeller | 59 | Director |
| Arthur B. Krause | 70 | Director |
| Richard T. O Brien | 57 | Director |
| Robert D. Taylor | 64 | Director |

**John J. Sherman.** Mr. Sherman has served as President, Chief Executive Officer and a director since March 2001, and of our predecessor from 1997 until July 2001. Prior to joining our predecessor, he was a vice president with Dynegy Inc. from 1996 through 1997. He was responsible for all downstream propane marketing operations, which at the time were the country s largest. From 1991 through 1996, Mr. Sherman was the president of LPG Services Group, Inc., a company he co-founded and grew to become one of the nation s largest wholesale marketers of propane before Dynegy acquired LPG Services in 1996. From 1984 through 1991, Mr. Sherman was a vice president and member of the management committee of Ferrellgas, which is one of the country s largest retail propane marketers. He also served as President, Chief Executive Officer and director of Inergy Holdings GP, LLC and is currently a director of Great Plains Energy Inc. We believe the breadth of Mr. Sherman s experience in the energy industry, through his current position as the President and CEO and his past employment described above, as well as his current board of director positions, has given him valuable knowledge about our business and our industry that makes him an asset to the board of directors of Inergy GP.

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**Phillip L. Elbert.** Mr. Elbert has served as President and Chief Operating Officer Propane Operations since September 2007 and Executive Vice President Propane Operations and director since March 2001. He joined our predecessor as Executive Vice President Operations in connection with our acquisition of the Hoosier Propane Group in January 2001. Mr. Elbert joined the Hoosier Propane Group in 1992 and was responsible for overall operations, including Hoosier s retail, wholesale and transportation divisions. From 1987 through 1992, he was employed by Ferrellgas, serving in a number of management positions relating to retail, transportation and supply. Prior to joining Ferrellgas, he was employed by Buckeye Gas Products, a large propane marketer from 1981 to 1987. He also served as the President and Chief Operating Officer Propane Operations of Inergy Holdings GP, LLC. Through his various leadership positions described above, Mr. Elbert has gained valuable experience in evaluating the financial performance and operations of companies in the propane industry, which makes him a valuable member of the board of directors of Inergy GP.

**R. Brooks Sherman, Jr.** Mr. Brooks Sherman, Jr. (no relation to Mr. John Sherman) has served as Executive Vice President since September 2007, Senior Vice President since September 2002 and Chief Financial Officer since March 2001. Mr. Sherman previously served as Vice President from March 2001 until September 2002. He joined our predecessor in December 2000 as Vice President and Chief Financial Officer. From 1999 until joining our predecessor, he served as Chief Financial Officer of MCM Capital Group. From 1996 through 1999, Mr. Sherman was employed by National Propane Partners, a publicly traded master limited partnership, first as its controller and chief accounting officer and subsequently as its chief financial officer. From 1995 to 1996, Mr. Sherman served as chief financial officer for Berthel Fisher & Co. Leasing Inc. and prior to 1995, Mr. Sherman was in public accounting with Ernst & Young and KPMG Peat Marwick. He also served as Executive Vice President and Chief Financial Officer of Inergy Holdings GP, LLC.

**Carl A. Hughes.** Mr. Hughes has served as Senior Vice President of Business Development since September 2007 and Vice President of Business Development since March 2001. He joined our predecessor as Vice President of Business Development in 1998. From 1996 through 1998, he served as a regional manager for Dynegy Inc., responsible for propane activities in 17 midwestern and northeastern states. From 1993 through 1996, Mr. Hughes served as a regional marketing manager for LPG Services Group. From 1985 through 1992, Mr. Hughes was employed by Ferrellgas where he served in a variety of management positions.

**Laura L. Ozenberger.** Ms. Ozenberger has served as Senior Vice President General Counsel and Secretary since September 2007 and Vice President General Counsel and Secretary since February 2003. From 1990 to 2003, Ms. Ozenberger worked for Sprint Corporation. While at Sprint, Ms. Ozenberger served in a number of management roles in the Legal and Finance departments. Prior to 1990, Ms. Ozenberger was in a private legal practice. She also served as Senior Vice President General Counsel and Secretary of Inergy Holdings GP, LLC.

**William R. Moler.** Mr. Moler has served as Senior Vice President Natural Gas Midstream Operations since September 2007, Vice President of Midstream Operations since 2005 and Director of Midstream Operations since 2004. Prior to joining Inergy, Mr. Moler was with Westport Resources Corporation where he served as both General Manager of Marketing and Transportation Services and General Manager of Westport Field Services, LLC. Prior to Westport, Mr. Moler served in various leadership positions at Kinder Morgan, Inc.

**Warren H. Gfeller.** Mr. Gfeller has been a member of our general partner s board of directors since March 2001. He was a member of our predecessor s board of directors from January 2001 until July 2001. He has engaged in private investments since 1991. From 1984 to 1991, Mr. Gfeller served as president and chief executive officer of Ferrellgas, Inc., a retail and wholesale marketer of propane and other natural gas liquids. Mr. Gfeller began his career with Ferrellgas in 1983 as an executive vice president and financial officer. Prior to joining Ferrellgas, Mr. Gfeller was the Chief Financial Officer of Energy Sources, Inc. and a CPA at Arthur Young & Co. He also served as a director of Inergy Holdings GP, LLC, Zapata Corporation and Duckwall-Alco Stores, Inc. Mr. Gfeller worked for many years in the propane industry. This experience has given him a unique perspective on our operations, and, coupled with his extensive financial and accounting training and practice, has made him a valuable member of the board of directors of Inergy GP.

**Arthur B. Krause.** Mr. Krause has been a member of our general partner s board of directors since May 2003. Mr. Krause retired from Sprint Corporation in 2002, where he served as Executive Vice President and Chief Financial Officer from 1988 to 2002. He was President of United Telephone-Eastern Group from 1986 to 1988. From 1980 to 1986, he was Senior Vice President of United Telephone System. He currently serves as a director of Westar Energy and served as a director of Inergy Holdings GP, LLC from April 2005 until November 2010. Mr. Krause s prior leadership experience and his extensive financial and accounting training and practice have made him a valuable member of the board of directors of Inergy GP.

**Richard T. O Brien.** Mr. O Brien was appointed to the board of our general partner in November 2010. Mr. O Brien currently serves as the President and Chief Executive Officer and a director of Newmont Mining Corporation, one of the world s largest gold producers, based in Denver, Colorado. From April 2001 until September 2005, Mr. O Brien served as the Executive Vice President and Chief Financial Officer of AGL Resources, a natural gas distributor headquartered in Atlanta, Georgia. He currently serves as a director of Vulcan Materials Company and served as a director of Inergy Holdings GP, LLC from May 2006 until November 2010. Mr. O Brien brings a strong and unique background and set of skills to the board, including over 20 years of broad financial executive and operational experience in the energy, power and natural resources businesses.

**Robert D. Taylor.** Mr. Taylor joined our general partner s board of directors in May 2005. Mr. Taylor, a CPA, has served as chief executive officer of Executive AirShare Corporation since November 2001. Mr. Taylor also served as president of Executive AirShare Corporation from November 2001 until November 2007. From August 1998 until September 2001, Mr. Taylor was president of Executive Aircraft Corporation. Mr. Taylor serves as a director of Blue Valley BanCorp. and Elecsys Corporation and previously served as a director of Commercial Federal Corporation. The breadth of Mr. Taylor s operational, financial and business experience has developed through his experience as chief executive officer of Executive AirShare Corporation and makes him an important voice as an independent director on the board of directors of Inergy GP.

**Independent Directors**

Messrs. Gfeller, Krause, O Brien and Taylor qualify as independent pursuant to independence standards established by the New York Stock Exchange ( NYSE ) as set forth in Section 303A.02 of its Listed Company Manual. To be considered an independent director under the NYSE listing standards, the board of directors must affirmatively determine that a director has no material relationship with the Partnership. In making this determination, the board of directors adheres to all of the specific tests for independence included in the NYSE listing standards and considers all other facts and circumstances it deems necessary or advisable.

**Board Leadership Structure and Risk Oversight**

*Board Leadership Structure*

The board has no policy that requires that the positions of the Chairman of the Board (the Chairman ) and the Chief Executive Officer be separate or that they be held by the same individual. The board believes that this determination should be based on circumstances existing from time to time, including the composition, skills and experience of the board and its members, specific challenges faced by the Company or the industry in which it operates, and governance efficiency. Based on these factors, John J. Sherman serves as our Chairman and Chief Executive Officer.

Our non-management directors will meet in regularly scheduled sessions. Our non-management directors have appointed Warren H. Gfeller as the lead director to preside at such meetings. We have established a procedure by which unitholders or interested parties may communicate directly with the board of directors, any committee of the board, any of the independent directors or any one director serving on the board of directors by sending written correspondence addressed to the desired person, committee or group to the attention of Laura Ozenberger at Inergy, L.P., Two Brush Creek Blvd., Suite 200, Kansas City, MO 64112. Communications are distributed to the board of directors, or to any individual director or directors as appropriate, depending on the facts and circumstances outlined in the communication.

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*Risk Oversight*

We face a number of risks, including environmental and regulatory risks, and others, such as the impact of competition and weather conditions. Management is responsible for the day-to-day management of risks our partnership faces, while the board of directors, as a whole and through its committees, has responsibility for the oversight of risk management. In fulfilling its risk oversight role, the board of directors must determine whether risk management processes designed and implemented by our management are adequate and functioning as designed. Senior management regularly delivers presentations to the board of directors on strategic matters, operations, risk management and other matters, and is available to address any questions or concerns raised by the board. Specifically, at quarterly board meetings, senior management delivers a presentation on risk management focused on one or more key aspects of our business as selected by the board or senior management. Board meetings also regularly include discussions with senior management regarding strategies, key challenges and risks and opportunities for our partnership.

Our board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists with risk management oversight in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements and our risk management policy relating to our hedging program. The compensation committee assists the board of directors with risk management relating to our compensation policies and programs.

**Board Committees**

*Audit Committee*

The members of the audit committee must meet the independence standards established by the NYSE. The members of the audit committee are Arthur B. Krause, Warren H. Gfeller and Robert D. Taylor. The board of directors of our general partner has determined that Mr. Gfeller is an audit committee financial expert based upon the experience stated in his biography. We believe that he is independent of management. The audit committee s primary responsibilities are to monitor: (a) the integrity of our financial reporting process and internal control system; (b) the independence and performance of the independent registered public accounting firm; and (c) the disclosure controls and procedures established by management.

*Conflicts Committee*

Our general partner may appoint two independent directors to serve on a conflicts committee to review specific matters which the board of directors believes may involve conflicts of interest. A conflicts committee will determine if the resolution of any conflict of interest submitted to it is fair and reasonable to us. In addition to satisfying certain other requirements, the members of the conflicts committee must meet the independence standards for service on an audit committee of a board of directors, which standards are established by the NYSE. Any matters approved by the conflicts committee will be conclusively deemed to be fair and reasonable to us, approved by all of our partners and not a breach by our general partner of any duties it may owe us or our unitholders.

*Compensation Committee*

Two members of the board of directors also serve on a compensation committee, which oversees compensation decisions for the officers of Inergy GP, LLC, as well as the compensation plans described below. The members of the compensation committee are Warren H. Gfeller and Arthur B. Krause.

**Section 16(a) Beneficial Ownership Reporting Compliance**

Section 16(a) of the Securities Exchange Act of 1934 requires our partnership s directors and executive officers, and persons who own more than 10% of any class of equity securities of our partnership registered under Section 12 of the Exchange Act, to file with the Securities and Exchange Commission initial reports of ownership and report of changes in ownership in such securities and other equity securities of our partnership. Securities and Exchange Commission regulations require directors, executive officers and greater than 10% unitholders to furnish our partnership with copies of all Section 16(a) reports they file. To our knowledge, based solely on review of the reports furnished to us and written representations that no other reports were required, during the fiscal year ended September 30, 2011, all section 16(a) filing requirements applicable to our directors, executive officers and greater than 10% unitholders, were met except that Carl A. Hughes failed to timely file a Form 5 for the gift of 2,880 common units to his children. Mr. Hughes has since filed the appropriate Section 16(a) report with respect to this transaction.

**Code of Ethics**

We have adopted a code of ethics that applies to our principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions, as well as to all of our other employees. Additionally, the board of directors has adopted corporate governance guidelines for the directors and the board. The code of ethics and corporate governance guidelines may be found on our website at www.inergylp.com.

**Item 11. Executive Compensation.**

**Compensation Discussion and Analysis**

**Introduction**

We do not directly employ any of the persons responsible for managing our business. Inergy GP, LLC, our general partner, manages our operations and activities, and its board of directors and officers make decisions on our behalf. The compensation of the directors and certain officers of our general partner is determined by the compensation committee of the board of directors of our general partner.

For purposes of this Compensation Discussion and Analysis our named executive officers are John J. Sherman, R. Brooks Sherman, Jr., Phillip L. Elbert, William R. Moler and Laura L. Ozenberger.

**Compensation Philosophy and Objectives**

We employ a compensation philosophy that emphasizes pay for performance. The primary measure of our performance long-term is our ability to increase sustainable cash distributions to our unitholders and the related unitholder value realized. We believe that by tying a substantial portion of each named executive officer s total compensation to financial performance metrics based on such distributions and unitholder value, our pay-for-performance approach aligns the interests of executive officers with that of our unitholders. Accordingly, the objectives of our total compensation program consist of:

- aligning executive compensation incentives with the creation of unitholder value and the growth of cash earnings on behalf of our unitholders;
- balancing short and long-term performance;
- tying short-and long-term compensation to the achievement of performance objectives (partnership, business unit, department and/or individual); and
- attracting and retaining the best possible executive talent for the benefit of our unitholders.

By accomplishing these objectives, we hope to optimize long-term unitholder value.

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**Compensation Setting Process**

*Chief Executive Officer s Role in the Compensation Setting Process*

Our Chief Executive Officer plays a significant role in the compensation setting process. The most significant aspects of his role are:

- assisting in establishing business performance goals and objectives;
- evaluating executive officer and partnership performance;
- recommending compensation levels and awards for executive officers; and
- implementing the approved compensation plans.

The Chief Executive Officer makes recommendations to the compensation committee with respect to financial metrics to be used for performance-based awards as well as other recommendations regarding non-CEO executive compensation, which may be based on our performance, individual performance and the peer group compensation market analysis. The compensation committee considers this information when establishing the total compensation package of the executive officers. The Chief Executive Officer s performance and compensation is reviewed, evaluated and established separately by the compensation committee based on criteria similar to those used for non-CEO executive compensation.

**Market Analysis**

To evaluate the competitiveness of both total executive compensation and the individual compensation components, the compensation committee utilizes compensation data about other companies to assist in assessing executive compensation levels, including the individual base salary and incentive components. The data typically consists of an analysis of total compensation, as well as base salary amounts, annual incentive awards, and long-term incentive awards and is compiled from public filings of similar companies, as well as companies in the Kansas City region. We selected these peer companies because, like us, they are: (i) MLPs with significant propane operations, or (ii) MLPs with growing midstream operations. We chose the regional companies because they are public companies with which we compete for talent in the local employment market.

| Peer MLP Companies | Regional Companies |
|---|---|
| Amerigas Partners, L.P. | Cerner Corporation |
| Copano Energy, LLC | DST Systems, Inc. |
| Energy Transfer Partners, L.P. | Ferrellgas Partners, L.P. |
| Ferrellgas Partners, L.P. | Garmin Ltd. |
| Markwest Energy Partners, L.P. | Great Plains Energy Incorporated |
| Plains All American Pipeline, L.P. | Kansas City Southern |
| Regency Energy Partners, L.P. | |
| Suburban Propane Partners, L.P. | |
| Targa Resources Partners, L.P. | |

The compensation committee utilizes the market data as a general guideline in making compensation-related decisions. When determining compensation amounts for our executive officers, the compensation committee uses data from our peer group as a reference for determining:

amount of total compensation;

individual components of compensation; and

relative proportion of each component of compensation base salary, annual incentive award opportunity and long-term incentive award value.

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While our general objective for total compensation is at or above the median of the peer group data with a significant portion of total compensation at risk, we do not require a strict policy of achieving a specific percentile relationship of actual pay to market pay as some companies do. The compensation committee has the full discretion to disregard the market data and award compensation at a different range if there are factors warranting the adjustment. Such factors may include alignment of the officer s position within the peer group data, experience and value he or she brings to the role, sustained high-level performance, demonstrated success in meeting key financial and other business objectives and the amount of the officer s pay relative to the pay of his or her peers within our partnership.

In addition, the actual value delivered to any executive may be above or below that range depending upon our financial results, common unit price performance and the individual s performance.

The compensation committee may in its discretion retain the services of a third-party compensation consultant, but did not retain any such consultants this fiscal year.

In collecting the peer group data for the compensation committee for fiscal 2011, we compared each officer s position against like positions for our peer group. The data was adjusted for differences in various financial and operating metrics, including revenues, customer base, numbers of employees and scope for each position relative to comparator company positions. Based on the difficulty in assessing appropriate comparisons of relative value for equity awards, no specific comparison of equity awards of our peer companies was made for long-term incentive opportunity values although the market value of equity holdings of similarly situated employees at our peer companies was generally considered.

**Elements of Compensation**

The principal elements of compensation for the named executive officers are the following:

- base salary;
- incentive awards;
- long-term incentive plan awards; and
- retirement and health benefits.

*Base Salary*

Base salary is designed to compensate executives for the responsibility of the level of the position they hold and sustained individual performance (including experience, scope of responsibility, results achieved and future potential). Base salary amounts were initially established in the employment agreements of our named executive officers and we historically have not made annual adjustments to the salaries of our named executive officers. We do, however, review the salaries of our named executive officers on an annual basis as well as at the time of promotion, or when entering into or renewing an employment agreement and may adjust salaries due to changes in responsibilities or market conditions. In determining the amount of any adjustments, the compensation committee uses market data as a tool for assessing the reasonableness of the base salary amounts of the named executive officers as compared to the compensation of executives in similar positions with similar responsibility levels in our industry and in our region. However, the final determination of base salary amounts is within the compensation committee s subjective discretion.

On November 24, 2010, John Sherman entered into an employment agreement that increased his base salary from $350,000 to $400,000 and on January 27, 2011, Laura L. Ozenberger entered into a new employment agreement that increased her base salary from $200,000 to $250,000. Additionally, the compensation committee determined that effective January 1, 2012, the base salaries for Phillip L. Elbert, R. Brooks Sherman, Jr. and William R. Moler should be increased to $300,000, $300,000 and $250,000, respectively. This is the first salary increase for the named executive officers since October 1, 2007. We believe these increases are warranted based on the increased responsibilities of these executives due to the growth of the partnership from a primarily propane business with approximately $210 million of Adjusted EBITDA in fiscal 2007 to a diversified energy infrastructure and distribution company with approximately $372 million of Adjusted EBITDA in fiscal 2011, and comparable compensation of executives in similar positions with similar responsibility levels in our industry and in our region.

*Incentive Awards*

Incentive awards are designed to reward the performance of key employees, including the named executive officers, by providing annual incentive opportunities for the partnership s achievement of its annual financial performance goals. In particular, these bonus awards are provided to the named executive officers in order to provide competitive incentives to these executives who can significantly impact performance and promote achievement of our short-term business objectives. Under the terms of their respective employment agreements, each named executive officer is eligible, upon the achievement of certain subjective and objective criteria, to receive a cash bonus amount that is up to 100% of the named executive officer s base salary.

The sole metric used to determine whether bonuses would be paid to the named executive officers in fiscal 2011 was our achievement of the target of earnings before income taxes, plus net interest expense, depreciation and amortization expense, further adjusted to exclude the gain or loss on derivative contracts associated with retail propane fixed price sales contracts, the gain or loss on the disposal of assets, long-term incentive and equity compensation expenses and transaction costs ( Adjusted EBITDA ). We selected this metric because we believe it closely aligns the focus of our named executive officers with the increase in unitholder value. In addition, this target was communicated to our unitholders and analysts as guidance at the beginning of the 2011 fiscal year.

The following table summarizes the incentive award targets and our actual results for the fiscal year ended September 30, 2011 (*in millions*):

| | Target | Actual |
|---|---|---|
| Adjusted EBITDA[(1)] | $ 421.0[(2)] | $ 372.2 |

(1) Adjusted EBITDA represents EBITDA excluding (1) non-cash gains or losses on derivative contracts associated with retail propane fixed price sales contracts, (2) long-term incentive and equity compensation expenses, (3) gains or losses on disposals of assets and (4) transaction costs. For a reconciliation of EBITDA to Adjusted EBITDA refer to page 43 of this annual report on Form 10-K.

(2) The compensation committee initially approved an Adjusted EBITDA target of $431.0 million, but decreased the target to $421.0 million due to regulatory delays on certain midstream growth projects.

As reflected in the table above, we did not meet the target for Adjusted EBITDA in fiscal 2011. Accordingly, in accordance with the terms of the employment agreements of the named executive officers, there were no short-term incentive awards for fiscal 2011.

*Long-Term Incentive Plan Awards*

Long-term incentive awards for the named executive officers are granted under the Inergy Long Term Incentive Plan in order to promote achievement of our primary long-term strategic business objective of increasing distributable cash flow and increasing unitholder value. These plans are designed to align the economic interests of key employees and directors with those of our common unitholders and to provide an incentive to management for continuous employment with the general partner and its affiliates. Long-term incentive compensation is based upon the common units representing limited partnership interests in us and primarily consists of restricted units. We have no policy regarding the allocation of different types of equity awards; rather, we determine which type of award will be granted due to a number of different factors, including, cost to the partnership, perceived value to the employee and economic conditions.

We do not make systematic annual awards to the named executive officers. Generally, we believe that a two- to five-year grant cycle (and complete vesting over five years) provides a balance between a meaningful retention period for us and a visible, reachable reward for the executive officers. New awards are generally synchronized with the remaining time-vesting requirements of outstanding awards in a manner designed to encourage extended retention of the named executive officers.

In determining the size of the equity awards, the compensation committee primarily considers the grant date value and vesting schedule of the awards as both a retention tool and performance incentive, the experience and skills of the executive officers as well as their contributions to our operational and financial performance, the economic and retention value of outstanding equity awards held by the executives, the amount of cash distributions that would be received by the executives and cost to our partnership. These factors were not given any specific weight; rather, they were subjectively evaluated by the compensation committee. The value of the equity was also compared to the equity awards of our peer companies to assess reasonableness of the awards without imposing specific targets.

Consistent with our general policy of not making systematic annual awards, we did not make broad based equity awards in fiscal 2011. On January 27, 2011, the compensation committee awarded Laura L. Ozenberger 80,000 restricted units.

The award to Ms. Ozenberger was partial consideration for entering into a five-year employment agreement with the general partner, which included a two-year noncompete provision. This award vests in four equal annual installments beginning on the second anniversary of the grant date. This award is subject to forfeiture if on any vesting date the annualized distribution paid on Inergy, L.P. common units is less than $2.74.

The amount of the award was determined based on a review of target total compensation levels, including base salary, short term incentive bonuses and these long term awards. The compensation committee then annualized this award by dividing the total value by five in accordance with the ultimate vesting. The total annualized target compensation was determined to be near the median of the peer group data considering her respective skills, experience and past performance.

*Risk Assessment Related to our Compensation Structure.*

We believe that the compensation plans and programs for our executive officers, as well as other employees, are appropriately structured and are not reasonably likely to result in a material risk. We believe these compensation plans and programs are structured in a manner that does not promote excessive risk-taking that could reward poor judgment. We also believe that we have allocated compensation among base salary and short and long-term compensation in such a way as to not encourage excessive risk-taking. In particular, we generally do not adjust base annual salaries for executive officers and other employees significantly from year to year, and therefore the annual base salary of our employees is not generally impacted by our overall financial performance or the financial performance of an operating segment. We generally determine whether, and to what extent, executive officers and other employees receive incentive cash bonuses based on achievement of specified financial performance objectives. For example, in fiscal 2011, Inergy announced EBITDA guidance that it believed was reasonable in light of past performance and market conditions, and the compensation committee took into account whether we met or exceeded that public guidance for the purpose of determining incentive cash bonuses for its executive officers following the completion of the fiscal year. Furthermore, we use restricted units rather than unit options for equity awards because restricted units retain value even in a depressed market so that employees are less likely to take unreasonable risks to get, or keep, options in-the-money. In addition, we believe the award of restricted units aligns the interests of the recipient with our unitholders because restricted units have upside and downside risk.

*Inergy Long Term Incentive Plan*

Our general partner sponsors the Inergy Long Term Incentive Plan for its directors, consultants and employees and the employees and consultants of its affiliates who perform services for us. The plan is administered by the compensation committee of the general partner s board of directors.

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*Unit Options*

The Inergy Long Term Incentive Plan currently permits, and our general partner has made, grants of options covering common units. Unit options will have an exercise price equal to the fair market value of the units on the date of grant. In general, unit options will become exercisable over a five-year period. In addition, the unit options will become exercisable upon a change of control of the general partner or us. Generally, unit options will expire after ten years.

Upon exercise of a unit option, our general partner will acquire common units in the open market, or directly from us or any other person, or use common units already owned by the general partner, or any combination of the foregoing. The general partner will be entitled to reimbursement by us for the difference between the cost incurred by the general partner in acquiring these common units and the proceeds received by the general partner from an optionee at the time of exercise. Thus, the cost of the unit options will be borne by us. If we issue new common units upon exercise of the unit options, the total number of common units outstanding will increase and the general partner will pay us the proceeds it received from the optionee upon exercise of the unit options. The unit option plan has been designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders.

In connection with the Simplification Transaction, on November 5, 2010, each vested and unvested option to purchase Holdings common units granted under the Inergy Holdings Long Term Incentive Plan was assumed by Inergy and converted into an option to purchase Inergy, L.P. units to be issued pursuant to the Inergy Long Term Incentive Plan. Each Holdings unit option assumed by Inergy continues to have the same terms and conditions set forth in the Inergy Holdings Long Term Incentive Plan except that they are exercisable for that number of whole Inergy, L.P. units equal to the product of the number of Holdings common units that were subject to such Holdings unit option multiplied by 0.77, rounded down to the nearest whole number, and the per unit exercise price for the Inergy, L.P. units subject to such assumed Holdings unit option is equal to the quotient determined by dividing the exercise price per Holdings common unit of such Holdings unit option by 0.77, rounded up to the nearest whole cent.

*Restricted Units*

The Inergy Long Term Incentive Plan currently permits, and our general partner has made, grants of restricted units. Restricted units are subject to a restricted period the terms of which are set forth in a restricted unit award agreement. In general, restricted units vest over a five-year period. The individual award agreement also sets forth the conditions under which the restricted units may become vested or forfeited, which may include, without limitation, the accelerated vesting upon the achievement of specified performance goals, or the forfeiture for failing to achieve specified performance goals and such other terms and conditions as the committee may establish. Unless otherwise specifically provided for in an award agreement, distributions are paid to the holder of the restricted units without restriction. Restricted units are designed to furnish additional compensation to employees and directors and to align their economic interests with those of common unitholders.

In connection with the Simplification Transaction, on November 5, 2010, each unvested Holdings restricted unit outstanding under the Inergy Holdings Long Term Incentive Plan was assumed by Inergy and converted into a restricted Inergy, L.P. unit to be issued pursuant to the Inergy Long Term Incentive Plan. Each Holdings restricted unit assumed continues to have the same terms and conditions set forth in the Inergy Holdings Long Term Incentive Plan except that they were converted into that number of restricted Inergy, L.P. equal to the product of the number of Holdings restricted units multiplied by 0.77, rounded down to the nearest whole number of Inergy, L.P. units.

*Termination and Amendment*

The general partner s board of directors in its discretion may terminate the Inergy Long Term Incentive Plan at any time with respect to any common units for which a grant has not yet been made. The general partner s board of directors also has the right to alter or amend Inergy Long Term Incentive Plan from time to time, including increasing the number of common units with respect to which awards may be granted subject to unitholder approval as required by the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of the participant.

**Other Compensation Related Matters**

*Retirement and Health Benefits*

We offer a variety of health and welfare and retirement programs to all eligible employees. The named executive officers are eligible for the same programs on the same basis as other employees. We maintain a 401(k) retirement plan that provides eligible employees with an opportunity to save for retirement on a tax advantages basis. We match 50% of the first 6% of the deferral to the retirement plan (not to exceed the maximum amount permitted by law) made by eligible participants. Our executive officers are also eligible to participate in additional employee benefits available to our other employees.

*Perquisites and Other Compensation*

We do not provide perquisites or other personal benefits to any of the named executive officers.

*Severance Benefits*

We maintain employment agreements with all our named executive officers to ensure they will perform their roles for an extended period of time and not compete with us upon termination of employment. These agreements are described in more detail elsewhere in this Annual report. Please read Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table Employment Agreements. These agreements do not provide any form of severance payment upon a change in control. However, the agreements do provide for continued salary payments following termination of employment without cause (as defined in the employment agreements). Thus, the continued salary provisions only become operative in the event of a change in control if such change in control is accompanied by a change in employment status (such as the termination of employment). We believe this arrangement is appropriate because it provides assurance to the executive, but does not offer a windfall to the executive when there has been no real change in employment status. In addition, the Inergy Long Term Incentive Plan provides for accelerated vesting triggered upon a change of control.

*Tax Deductibility of Compensation*

With respect to the deduction limitations under Section 162(m) of the Code, we are a limited partnership and do not meet the definition of a corporation under Section 162(m).

**Compensation Committee Report**

We have reviewed and discussed the foregoing Compensation Discussion and Analysis with management. Based on our review and discussion with management, we have recommended that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K for the year ended September 30, 2011.

Warren H. Gfeller

Arthur B. Krause

Members of the Compensation Committee

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**2011 Summary Compensation Table**

The following table sets forth the cash and non-cash compensation earned for the years ended September 30, 2011, September 30, 2010 and September 30, 2009, by each person who served as the Chief Executive Officer, Chief Financial Officer and the three other highest paid executive officers (the named executive officers ) during fiscal 2011.

| Name and Principal Position | Fiscal Year | Salary ($) | Bonus ($) | Stock Awards ($)(1) | Option Awards ($) | Non-Equity Incentive Plan Compensation ($) | All Other Compensation ($) | Total ($) |
|---|---|---|---|---|---|---|---|---|
| John. J. Sherman | 2011 | 393,653 | | | | | 11,319(3) | 404,972 |
| *President and Chief* | 2010 | 350,000 | | | | | 9,828 | 359,828 |
| *Executive Officer* | 2009 | 350,000 | | | | 350,000 | 7,137 | 707,137 |
| R. Brooks Sherman, Jr. | 2011 | 225,000 | | | | | 641,452(3) | 866,452 |
| *Executive Vice President and Chief* | 2010 | 225,000 | | 5,669,950 | | | 416,382 | 6,311,332 |
| *Financial Officer* | 2009 | 225,000 | | | | 225,000 | 105,047 | 727,130 |
| Phillip L. Elbert | 2011 | 275,000 | | | | | 837,567(3) | 1,112,567 |
| *President and Chief* | 2010 | 275,000 | | 7,216,300 | | | 549,038 | 8,040,338 |
| *Operating Officer* | 2009 | 275,000 | | | | 275,000 | 148,388 | 917,283 |
| *Propane Operations* | | | | | | | | |
| William R. Moler | 2011 | 200,000 | | | | | 451,694(3) | 651,694 |
| *Senior Vice President-* | 2010 | 200,000 | | 3,254,625 | | | 308,235 | 3,762,860 |
| *Natural Gas Midstream Operations* | 2009 | 200,000 | 55,000 | | | 200,000 | 98,633 | 675,029 |
| Laura L. Ozenberger | 2011 | 235,385 | | 3,264,800(2) | | | 287,772(3) | 3,787,957 |
| *Senior Vice President General Counsel and* | 2010 | 200,000 | 200,000 | | | | 102,125 | 502,125 |
| *Secretary* | 2009 | 200,000 | | | | 200,000 | 73,512 | 473,512 |

(1) The material terms of our outstanding LTIP awards to our executive officers are described in Compensation Discussion and Analysis Long-Term Incentive Plans. Equity award amounts reflect the aggregate grant date fair value of unit awards granted during the periods presented.

(2) As discussed in the Compensation Discussion and Analysis on January 27, 2011, Laura L. Ozenberger was awarded 80,000 Inergy, L.P. restricted units. This award vests in 25% equal annual installments beginning two years from the grant date. This award is subject to forfeiture if on any vesting date the annualized distribution paid on Inergy, L.P. common units is less than $2.74.

(3) Consists of: (i) distributions paid on restricted units granted under the Long-Term Incentive Plan (R. Brooks Sherman, Jr. $634,936, Phillip L. Elbert $823,257, William R. Moler $444,992, Laura L. Ozenberger $279,930); and (ii) matching contributions to the partnership s 401(k) Plan and Employee Unit Purchase Plan for each named executive officer . The partnership does not provide perquisites and other personal benefits.

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**2011 Grants of Plan Based Awards Table**

The following table provides information concerning each grant of an award made to our named executive officers in the last completed fiscal year under any plan, including awards that have been transferred.

| | | Estimated Future Payouts Under Incentive Plan Awards | | | | |
|---|---|---|---|---|---|---|
| **Name** | **Grant Date** | **Threshold ($)** | **Target ($)** | **Maximum ($)(1)** | **All Other Stock Awards(#)** | **Grant Date Fair Value of Stock and Option Awards ($)** |
| John J. Sherman | | 0 | 400,000 | 400,000 | | |
| R. Brooks Sherman, Jr. | | 0 | 225,000 | 225,000 | | |
| Phillip L. Elbert | | 0 | 275,000 | 275,000 | | |
| William R. Moler | | 0 | 200,000 | 200,000 | | |
| Laura L. Ozenberger | 1/27/11 | 0 | 250,000 | 250,000 | 80,000(2) | 3,264,800 |

(1) The Maximum amount may be increased by the discretion of the Compensation Committee as described above in the Compensation Discussion and Analysis Incentive Awards.

(2) This award vests in 25% equal annual installments beginning two years from the grant date and is subject to forfeiture if on any vesting date the annualized distribution paid on Inergy, L.P. common units is less than $2.74.

**Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table**

A discussion of fiscal 2011 salaries and bonuses is included above in Compensation Discussion and Analysis. The following is a discussion of other material factors necessary to an understanding of the information disclosed in the Summary Compensation Table.

***Employment Agreements***

The following named executive officers have entered into employment agreements with our partnership:

- John J. Sherman President and Chief Executive Officer;
- R. Brooks Sherman, Jr., Executive Vice President Chief Financial Officer;
- Phillip L. Elbert, President and Chief Operating Officer Propane Operations;
- William R. Moler, Senior Vice President Natural Gas Midstream Operations; and
- Laura L. Ozenberger, Senior Vice President General Counsel and Secretary.

The following is a summary of the material provisions of these employment agreements, each of which is incorporated by reference herein as an exhibit to this report.

All of these employment agreements are substantially similar, with certain exceptions as set forth below. The employment agreements are for terms of five years. During the fiscal year, the annual salaries for these individuals are as follows:

John J. Sherman $400,000 (Mr. Sherman entered into a new five-year employment agreement on November 24, 2010, which increased his salary from $350,000 to $400,000)

R. Brooks Sherman, Jr. $225,000 (increases to $300,000 on January 1, 2012)

Phillip L. Elbert $275,000 (increases to $300,000 on January 1, 2012)

William R. Moler $200,000 (increases to $250,000 on January 1, 2012)

Laura L. Ozenberger $250,000 (Ms. Ozenberger entered into a new five-year employment agreement on January 27, 2011, which increased her salary from $200,000 to $250,000)

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These employees are reimbursed for all expenses in accordance with the general partner s policies. They are also eligible for fringe benefits normally provided to other employees.

All of the individuals are eligible for non-equity incentive compensation bonuses upon meeting certain established criteria for each year during the term of his or her employment. Please see Compensation Discussion and Analysis Incentive Awards for additional disclosure regarding these bonus awards.

Generally, unless waived by the general partner, in order for any of these individuals to receive any benefits under (i) the Inergy Long Term Incentive Plan, or (ii) the non-equity incentive compensation bonus, the individual must have been continuously employed by the general partner or one of our affiliates from the date of his or her employment agreement up to the date for determining eligibility to receive such amounts.

Each employment agreement contains confidentiality and noncompetition provisions. Also, each employment agreement contains a disclosure and assignment of inventions clause that requires the employee to disclose the existence of any invention and assign such employee s right in such invention to the general partner.

With respect to each of the named executive officers, in the event such person s employment is terminated without cause, we will be required to continue making payments to such person for the remainder of the term of such person s employment agreement.

**Outstanding Equity Awards at Fiscal Year-End Table**

The following table summarizes the options and restricted units outstanding as of September 30, 2011, for the named executive officers. The table includes unit options and restricted units of Inergy, L.P. granted under the Inergy Long Term Incentive Plan.

| | OPTION AWARDS | | | | UNIT AWARDS | |
|---|---|---|---|---|---|---|
| **Name** | **Number of Securities Underlying Unexercised Options (#) Exercisable[1]** | **Number of Securities Underlying Unexercised Options (#) Unexercisable** | **Option Exercise Price($)** | **Option Expiration Date** | **Number of Units That Have Not Vested (#)** | **Market Value of Units That Have Not Vested ($)[1]** |
| John J. Sherman | | | | | | |
| R. Brooks Sherman, Jr. | | | | | 242,687[2] | 6,072,028 |
| Phillip L. Elbert | | | | | 318,325[2] | 7,964,491 |
| William R. Moler | | | | | 167,437[3] | 4,189,273 |
| Laura L. Ozenberger | 36,358 | | 9.74 | 6/19/15 | 123,312[4] | 3,085,266 |

(1) Market value for NRGY units based on the NYSE closing price of $25.02 on September 30, 2011.

(2) These awards vest in annual installments (25%, 25%, 50%) beginning three years from the grant date. 182,050 restricted units for R. Brooks Sherman, Jr. and 231,700 restricted units for Mr. Elbert are subject to forfeiture if on any vesting date the annualized distribution paid on an Inergy, L.P. common unit is less than $2.74.

(3) These awards vest in annual installments (25%, 25%, 50%) beginning three years from the grant date. 124,125 restricted units for Mr. Moler are subject to forfeiture if on any vesting date the annualized distribution paid on an Inergy, L.P. common unit is less than $2.70.

(4) 80,000 restricted units for Laura L. Ozenberger vest in 25% equal annual installments beginning two years from the grant date and are subject to forfeiture if on any vesting date the annualized distribution paid on Inergy, L.P. common units is less than $2.74. The remaining awards vest in annual installments (25%, 25%, 50%) beginning three years from the grant date.

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**2011 Option Exercises and Stock Vested Table**

The following table provides information regarding option exercises and restricted unit vesting during the fiscal year ended September 30, 2011, for the named executive officers.

| Name | Option Awards: Number of Units Acquired On Exercise (#) | Option Awards: Value Realized on Exercise ($) | Stock Awards: Number of Units Acquired On Vesting (#) | Stock Awards: Value Realized on Vesting ($) |
|---|---|---|---|---|
| John J. Sherman | | | | |
| R. Brooks Sherman, Jr. | 46,200 | 1,488,525 | 26,250(1) | 793,275 |
| Phillip L. Elbert | 92,400 | 2,643,276 | 37,500(1) | 1,133,250 |
| William R. Moler | 51,200 | 1,306,977 | 23,750(2) | 760,375 |
| Laura L. Ozenberger | 51,422 | 1,688,583 | 18,750(1) | 566,625 |

(1) Restricted units of Inergy Holdings, L.P. that vested on October 1, 2010.
(2) Includes 18,750 restricted units of Inergy Holdings, L.P. that vested on October 1, 2010, and 5,000 Inergy, L.P. restricted units that vested on March 20, 2011.

**Pension Benefits Table**

We do not offer any pension benefits.

**Nonqualified Deferred Compensation Table**

We have no non-qualified deferred compensation plans.

**Potential Payments upon a Change in Control or Termination**

*Employment Agreements*

Under the employment agreements with our named executive officers, Inergy GP, LLC may be required to pay certain amounts upon the employment termination of the named executive officer in certain circumstances. Upon the termination of employment of a named executive officer without Cause, the employment agreements entered into between Inergy GP, LLC and each of the named executive officers provide for salary continuation at the rate in effect at termination of the employee through the remaining term of the employment agreement. Consequently, no severance is payable in the event of any termination (i) as a result of death, disability, or legal incompetence, (ii) as a result of Inergy GP, LLC ceasing to carry on its business without assigning the employment agreement, (iii) as a result of Inergy GP, LLC becoming bankrupt, (iv) for Cause or (v) by the employee for any or no reason (except in the case of Mr. Moler, who is entitled to severance upon termination for Good Reason ). The occurrence of a change in control will not impact the severance amounts payable with respect to our named executive officers under the terms of their employment agreements. For purposes of the employment agreements:

Cause will generally be determined to have occurred in the event the:

employee has failed to perform his or her duties as an employee of Inergy GP, LLC, to perform any obligation under the employment agreement or to observe and abide by Inergy GP, LLC s policies and decisions, provided that Inergy GP, LLC has given employee reasonable notice of that failure and employee is unsuccessful in correcting that failure or in preventing its reoccurrence;

employee has refused to comply with specific directions of his/her supervisor or other superior, provided that such directions are consistent with the employee s position of employment;

employee has engaged in negligence or misconduct that is injurious to Inergy GP, LLC or any subsidiary, parent or affiliate of Inergy GP, LLC;

- employee has been convicted of, or has entered a plea of nolo contendere to, any crime involving the theft or willful destruction of money or other property, any crime involving moral turpitude or fraud, or any crime constituting a felony;

- employee has engaged in acts or omissions against Inergy GP, LLC or any subsidiary, parent or affiliate of Inergy GP, LLC constituting dishonesty, breach of fiduciary obligation, or intentional wrongdoing or misfeasance; or

- employee has used alcohol or drugs on the job, or has engaged in excessive absenteeism from the performance of his/her duties as Inergy GP, LLC s employee, other than for reasons of illness.

If a termination of a named executive officer by Inergy GP, LLC without Cause were to have occurred as of September 30, 2011, our named executive officers would have been entitled to the following:

- John J. Sherman would have received $1,633,333, representing base salary for the remaining 49 months of the term of his employment agreement (payable bi-monthly in arrears). For two years following termination of Mr. Sherman s employment he will continue to be subject to the non-competition provisions of his employment agreement.

- R. Brooks Sherman, Jr. would have received $750,000, representing base salary for the remaining 40 months of the term of his employment agreement (payable bi-monthly in arrears). For two years following termination of Mr. Sherman s employment he will continue to be subject to the non-competition provisions of his employment agreement.

- Phillip L. Elbert would have received $916,667, representing base salary for the remaining 40 months of the term of his employment agreement (payable bi-monthly in arrears). For two years following termination of Mr. Elbert s employment he will continue to be subject to the non-competition provisions of his employment agreement.

- William R. Moler would have received $616,667, representing base salary for the remaining 37 months of the term of his employment agreement (payable bi-monthly in arrears). In addition, to receiving severance payments upon a termination of employment without Cause, Mr. Moler is entitled to the same benefits if he terminates his employment for Good Reason which is defined as (i) employee being required by Inergy GP, LLC to be based at any office or location that is more than 75 miles from the location where employee was employed immediately preceding the date of the voluntary or involuntary termination of employee s employment, or (ii) a material reduction in employee s job duties and responsibilities. For two years following termination of Mr. Moler s employment he will continue to be subject to the non-competition provisions of his employment agreement.

- Laura L. Ozenberger would have received $1,062,500, representing base salary for the remaining 51 months of the term of her employment agreement (payable bi-monthly in arrears). For two years following termination of Ms. Ozenberger s employment she will continue to be subject to the non-competition provisions of her employment agreement.

*Inergy Long Term Incentive Plan*

Upon a change in control, all restricted units will automatically vest and become payable or exercisable, as the case may be, in full and any restricted periods or performance criteria will terminate or be deemed to have been achieved at the maximum level. There are no unvested unit options held by any of the named executive officers. For purposes of the Inergy Long Term Incentive Plan, a change in control means, and shall be deemed to have occurred upon one of the following events: (i) any sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Inergy Partners, LLC or Inergy, L.P. to any person or its affiliates, other than Inergy GP, LLC, the Partnership or any of their affiliates, or (ii) any merger, reorganization, consolidation or other transaction pursuant to which more than 50% of the combined voting power of the equity interests in Inergy GP, LLC or Inergy Partners, LLC ceases to be controlled by Inergy Holdings, L.P.

If a change in control were to have occurred as of September 30, 2011, all unvested restricted units held by the named executive officers under the Inergy Long Term Incentive Plan would have automatically vested, as follows:

| Name | Restricted Units under the Inergy Long Term Incentive Plan (#) | Total ($)(1) |
|---|---|---|
| John J. Sherman | | |
| R. Brooks Sherman, Jr. | 242,687 | 6,072,028 |
| Phillip L. Elbert | 318,325 | 7,964,028 |
| William R. Moler | 167,437 | 4,189,273 |
| Laura L. Ozenberger | 123,312 | 3,085,266 |

(1) The amounts included in the Total column are calculated by multiplying the number of restricted units by the closing per share price of our common units on September 30, 2011 ($25.02).

**Director Compensation Table**

The following table sets forth the cash and non-cash compensation for the year ended September 30, 2011, by each person who served as a non-employee director of Inergy GP, LLC.

| Name | Fees Earned or Paid in Cash ($) | Unit Awards ($)(1) | Option Awards ($) | All Other Compensation ($)(2) | Total ($) |
|---|---|---|---|---|---|
| Warren H. Gfeller | 57,000 | 49,978 | | 8,390 | 115,368 |
| Arthur B. Krause | 63,000 | 49,978 | | 8,390 | 121,368 |
| Robert D. Taylor | 51,250 | 49,978 | | 5,313 | 106,540 |
| Richard T. O Brien | 41,250 | 49,978 | | 5,525 | 96,753 |

(1) On April 1, 2011, Messrs. Gfeller, Krause, Taylor and O Brien were each awarded 1,242 Inergy, L.P. restricted units. Equity award amounts reflect the aggregate grant date fair value of unit awards granted during the period presented.

(2) Dollar value of distributions paid on restricted units during the fiscal year ended September 30, 2011.

**Compensation of Directors**

Officers of our general partner who also serve as directors do not receive additional compensation. Effective January 1, 2011, each director receives cash compensation of $40,000 per year for attending our regularly scheduled quarterly board meetings. Each non-employee director receives $1,000 for each special meeting of the board of directors attended and $1,000 per compensation or audit committee meeting attended. The chairman of the audit committee receives an annual fee of $10,000 per year and the chairman of the compensation committee receives an annual fee of $2,000 per year. Furthermore, each non-employee director receives an annual grant of restricted units under the long-term incentive plan equal to $50,000 in value. In April 2011, Messrs. Gfeller, Krause, Taylor and O Brien each received 1,242 restricted units under the Inergy Long Term Incentive Plan. These units vest ratably over three years beginning one year from the grant date. Each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees. Each director is fully indemnified for actions associated with being a director to the extent permitted under Delaware law.

**Compensation Committee Interlocks and Insider Participation**

The compensation committee of the board of directors of our general partner oversees the compensation of our executive officers. Warren H. Gfeller and Arthur B. Krause serve as the members of the compensation committee, and neither of them was an officer or employee of our partnership or any of its subsidiaries during fiscal 2011.

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**Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters.**

The following table sets forth certain information as of November 7, 2011, regarding the beneficial ownership of our common and class B units by:

- each person who then beneficially owned more than 5% of such units then outstanding;
- each of the executive officers of our general partner;
- each of the directors of our general partner; and
- all of the directors and executive officers of our general partner as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, executive officers or 5% or more unitholders, as the case may be.

| Name of Beneficial Owner(1) | Common and Class B Units Beneficially Owned | Percentage of Common and Class B Units Beneficially Owned |
|---|---|---|
| John J. Sherman | 18,887,879 | 14.4% |
| Phillip L. Elbert | 2,104,536 | 1.6 |
| Carl A. Hughes | 2,016,307 | 1.5 |
| R. Brooks Sherman, Jr. | 932,955 | * |
| William R. Moler | 167,981 | * |
| Laura L. Ozenberger | 153,205 | * |
| Warren H. Gfeller | 115,062 | * |
| Arthur B. Krause | 110,454 | * |
| Robert D. Taylor | 18,169 | * |
| Richard T. O Brien | 6,138 | * |
| All directors and executive officers as a group (10 persons) | 24,512,686 | 18.7% |

* Less than 1%

(1) Unless otherwise indicated, the address of each person listed above is: Two Brush Creek Boulevard, Suite 200, Kansas City, Missouri 64112. All persons listed have sole voting power and investment power with respect to their units unless otherwise indicated.

We refer you to Item 5 of this report for certain information regarding securities authorized for issuance under equity compensation plans.

**Item 13. Certain Relationships, Related Transactions and Director Independence.**

For a discussion of director independence, see Item 10. Directors, Executive Officers and Corporate Governance.

**Transactions with Related Persons**

***Simplification Transaction***

On August 7, 2010, we entered into an Agreement and Plan of Merger with our Managing General Partner Inergy Holdings, Inergy Holdings GP, LLC, the general partner of Holdings ( Holdings GP ), NRGP Limited Partner, LLC, a wholly owned subsidiary of Holdings GP ( New NRGP LP ), and NRGP MS, LLC, a wholly owned subsidiary of Holdings GP ( MergerCo ). Through a number of steps, Inergy Holdings merged into

MergerCo and the outstanding common units in Inergy Holdings were cancelled. In connection with the Merger, our incentive distribution rights, all of which were held by Inergy Holdings, were cancelled. We also acquired all of Inergy Holdings ownership interests in IPCH Acquisition Corp. ( IPCH ), a wholly owned subsidiary of Inergy Holdings, and in our Non-managing General Partner.

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Upon completion of the Merger, the holders of Inergy Holdings common units (the Holdings unitholders ) received 0.77 Inergy common units for each Inergy Holdings common unit that they owned (the exchange ratio ). The exchange ratio took into account the 1,080,453 Inergy common units that were owned by Inergy Holdings and were distributed to the Inergy Holdings unitholders as part of the Merger consideration. We issued approximately 35.2 million new common units in the Merger. We also issued 11,568,560 Class B Units to certain members of senior management and directors of Holdings GP and other beneficial owners of Inergy Holdings common units in lieu of issuing them an equivalent number of Inergy common units. The Class B Units do not receive cash distributions but instead receive distributions of additional Class B Units. The Class B units will convert automatically into Inergy common units on a one-for-one basis in two tranches over a two-year period. Immediately after the payment of the Inergy, L.P. common unit distribution on November 14, 2011, approximately 6.6 million Class B units converted into common units of Inergy, L.P. and are entitled to receive cash distributions.

The 789,202 common units owned by IPCH and the 2,837,034 common units and 0.6% general partner interest owned by Inergy Partners were converted into 4,867,252 Class A Units.

In connection the Simplification Transaction, we assumed and immediately paid off approximately $24.1 million outstanding indebtedness under Inergy Holdings credit agreements.

After the Simplification Transaction, Inergy Holdings continues to own 100% of our General Partner and continues to have the right to appoint the members of the board of directors of General Partner.

**Review, Approval or Ratification of Transactions with Related Persons**

Our Related Person Transactions Policy applies to any transaction since the beginning of our fiscal year (or currently proposed transaction) in which we or any of our subsidiaries was or is to be a participant, the amount involved exceeds $120,000 and any director, director nominee, executive officer, 5% or greater unitholder (or their immediate family members) had, has or will have a direct or indirect material interest. A transaction that would be covered by this policy would include, but not be limited to, any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) or any series of similar transactions, arrangements or relationships.

Under our Related Person Transactions Policy, related person transactions may be entered into or continue only if the transaction is deemed to be fair and reasonable to us, in accordance with the terms of our Partnership Agreement. Under our Partnership Agreement, transactions that represent a conflict of interest may be approved in one of three ways and, if approved in any of those ways, will be considered fair and reasonable to us and the holders of our common units. The three ways enumerated in our Related Person Transactions Policy for reaching this conclusion include:

(i) approval by the Conflicts Committee of the Board (the Conflicts Committee ) under Section 7.9 of the Partnership Agreement ( Special Approval );

(ii) approval by our Chief Executive Officer applying the criteria specified in Section 7.9 of the Partnership Agreement if the transaction is in the normal course of the Partnership s business and is (a) on terms no less favorable to the Partnership than those generally being provided to or available from unrelated third parties or (b) fair to the Partnership, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to the Partnership); and

(iii) approval by an independent committee of the Board (either the Audit Committee or a Special Committee) applying the criteria in Section 7.9 of the Partnership Agreement.

Once a transaction is approved in any of these ways, it is fair and reasonable and accordingly deemed (i) approved by all of our partners and (ii) not to be a breach of any fiduciary duties of general partner.

Our general partner determines in its discretion which method of approval is required depending on the circumstances.

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Under our Partnership Agreement, when determining whether a related person transaction is fair and reasonable, if our general partner elects to adopt a resolution or a course of action that has not received Special Approval, then our general partner may consider:

- the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;
- any customary or accepted industry practices and any customary or historical dealings with a particular person;
- any applicable generally accepted accounting practices or principles; and
- such additional factors as the general partner or conflicts committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

A related person transaction that is approved by the conflicts committee is, as discussed in greater detail above, conclusively deemed to be fair and reasonable to us. Under our Partnership Agreement, the material facts known to our general partner or any of our affiliates regarding the transaction must be disclosed to the conflicts committee at the time the committee gives its approval. When approving a related party transaction, the conflicts committee considers all factors it considers relevant, reasonable or appropriate under the circumstances, including the relative interests of any party to the transaction, customary industry practices and generally accepted accounting principles.

Under our Partnership Agreement, in the absence of bad faith by the general partner, the resolution, action or terms so made, taken or provided by the general partner with respect to approval of the related party transaction will not constitute a breach of the Partnership Agreement or any standard of fiduciary duty.

Under our Related Person Transactions Policy, as well as under our Partnership Agreement, there is no obligation to take any particular conflict to the conflicts committee empanelling that committee is entirely at the discretion of the general partner. In many ways, the decision to engage the conflicts committee can be analogized to the kinds of transactions for which a Delaware corporation might establish a special committee of independent directors. The general partner considers the specific facts and circumstances involved. Relevant facts would include:

- the nature and size of the transaction (e.g., transaction with a controlling unitholder, magnitude of consideration to be paid or received, impact of proposed transaction on the general partner and holders of common units);
- the related person s interest in the transaction;
- whether the transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances;
- if applicable, the availability of other sources of comparable services or products; and
- the financial costs involved, including costs for separate financial, legal and possibly other advisors at our expense.

When determining whether a related person transaction is in the normal course of our business and is (a) on terms no less favorable to us than those generally being provided to or available from unrelated third parties or (b) fair to us, taking into account the totality of the relationships between the parties involved (including other transactions that may be particularly favorable or advantageous to us), the general partner considers any facts and circumstances that it deems to be relevant, including:

the terms of the transaction, including the aggregate value;

the business purpose of the transaction;

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the relative interests of any party to such conflict, agreement, transaction or situation and the benefits and burdens relating to such interest;

whether the terms of the transaction are comparable to the terms that would exist in a similar transaction with an unaffiliated third party;

any customary or accepted industry practices;

any applicable generally accepted accounting practices or principles; and

such additional factors as the general partner or the conflicts committee determines in its sole discretion to be relevant, reasonable or appropriate under the circumstances.

**Rights of our General Partner**

Prior to the Simplification Transaction, Inergy Holdings owned an aggregate 6.6% interest in us inclusive of ownership of all of our non-managing general partner and our managing general partner. After the Simplification Transaction, Inergy Holdings owns our general partner which manages our operations and activities.

**Item 14. Principal Accountant Fees and Services.**

The following table presents fees billed for professional audit services rendered by Ernst & Young LLP for the audit of our annual financial statements and for other services for the years ended September 30, 2011 and 2010 (*in millions*):

| | Year Ended September 30, 2011 | 2010 |
|---|---|---|
| Audit fees[1] | $ 2.6 | $ 2.6 |
| Audit-related fees[2] | | |
| Total | $ 2.6 | $ 2.6 |

(1) Audit fees consist of assurance and related services that are reasonably related to the performance of the audit or review of our financial statements. This category includes fees related to the review of our quarterly and other SEC filings and services related to internal control assessments.

(2) Audit-related fees consist of due diligence fees associated with acquisition transactions, financial accounting and reporting consultations.

The audit committee of our general partner reviewed and approved all audit and non-audit services provided to us by Ernst & Young during fiscal 2011. For information regarding the audit committee s pre-approval policies and procedures related to the engagement by us of an independent accountant, see our audit committee charter on our website at www.inergylp.com.

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## PART IV

### Item 15. Exhibits and Financial Statement Schedules.

(a) Exhibits, Financial Statements and Financial Statement Schedules:

1. Financial Statements:

See Index Page for Financial Statements located on page 100.

2. Financial Statement Schedule:

Schedule II: Valuation and Qualifying Accounts located on page 141.

Other financial statement schedules have been omitted because they are either not required, are immaterial or are not applicable or because equivalent information has been included in the financial statements, the notes thereto or elsewhere herein.

3. Exhibits:

| Exhibit Number | Description |
|---|---|
| *2.1 | Agreement and Plan of Merger, dated August 7, 2010, among Inergy, L.P., Inergy GP, LLC, Inergy Holdings, LP, NRGP Limited Partner, LLC and NRGP MS, LLC (incorporated herein by reference to Exhibit 2.1 to Inergy, L.P. s Form 8-K filed on August 9, 2010) |
| *2.2 | First Amended and Restated Agreement and Plan of Merger, dated September 3, 2010, among Inergy, L.P., Inergy GP, LLC, Inergy Holdings, LP, NRGP Limited Partner, LLC and NRGP MS, LLC (incorporated herein by reference to Exhibit 2.1 to Inergy, L.P. s Form 8-K filed on September 7, 2010) |
| *2.3 | Purchase and Sale Agreement, dated September 3, 2010, between TP Gas Holding LLC and Inergy Midstream, LLC (incorporated herein by reference to Exhibit 2.1 to Inergy, L.P. s Form 8-K filed on September 7, 2010) |
| *3.1 | Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Registration Statement on Form S-1 (Registration No. 333-56976) filed on March 14, 2001) |
| *3.1 A | Certificate of Correction of Certificate of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 10-Q filed on May 12, 2003) |
| *3.2 | Second Amended and Restated Agreement of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 10-Q filed on February 13, 2004) |
| *3.2 A | Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership of Inergy L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 10-Q filed on May 14, 2004) |
| *3.2 B | Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 8-K filed on January 24, 2005) |
| *3.2 C | Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership of Inergy, L.P. (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 8-K/A filed on August 17, 2005) |
| *3.2 D | |

Third Amended and Restated Agreement of Limited Partnership of Inergy, L.P., dated as of November 5, 2010 (incorporated herein by reference to Exhibit 3.1 to Inergy, L.P. s Form 8-K filed on November 5, 2010)

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| Exhibit Number | Description |
|---|---|
| *3.3 | Certificate of Formation of Inergy Propane, LLC, as amended (incorporated herein by reference to Exhibit 3.3 to Inergy, L.P. s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001) |
| *3.4 | Third Amended and Restated Limited Liability Company Agreement of Inergy Propane, LLC, dated as of July 31, 2001 (incorporated herein by reference to Exhibit 3.4 to Inergy, L.P. s Registration Statement on Form S-1 (Registration No. 333-89010) filed on May 24, 2002) |
| *3.5 | Certificate of Formation of Inergy GP, LLC (incorporated herein by reference to Exhibit 3.5 to Inergy, L.P. s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001) |
| *3.6 | Limited Liability Company Agreement of Inergy GP, LLC (incorporated herein by reference to Exhibit 3.6 to Inergy, L.P. s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001) |
| *3.7 | Certificate of Formation of Inergy Partners, LLC, as amended (incorporated herein by reference to Exhibit 3.7 to Inergy, L.P. s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001) |
| *3.8 | Second Amended and Restated Limited Liability Company Agreement of Inergy Partners, LLC, dated as of July 31, 2001 (incorporated herein by reference to Exhibit 3.8 to Inergy, L.P. s Registration Statement on Form S-1 (Registration No. 333-89010) filed on May 24, 2002) |
| *3.9 | Certificate of Formation of Inergy Midstream, LLC (formerly Inergy Acquisition Company, LLC) |
| *3.10 | Certificate of Amendment to the Certificate of Formation of Inergy Midstream, LLC (formerly Inergy Acquisition Company, LLC) |
| *3.11 | Limited Liability Company Agreement of Inergy Midstream, LLC (formerly Inergy Acquisition Company, LLC), dated as of September 21, 2004 |
| *4.1 | Specimen Unit Certificate for Common Units (incorporated herein by reference to Exhibit 4.3 to Inergy L.P. s Registration Statement on Form S-1/A (Registration No. 333-56976) filed on May 7, 2001) |
| *4.2 | Indenture, dated as of February 2, 2009, among Inergy, L.P., Inergy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Inergy, L.P. s Form 8-K filed on February 3, 2009) |
| *4.3 | First Supplemental Indenture and Amendment Subsidiary Guarantee, dated as of November 5, 2010, to the Indenture, dated as of February 2, 2009 (incorporated herein by reference to Exhibit 10.4 to Inergy, L.P. s Form 8-K filed on November 5, 2010) |
| *4.4 | Indenture, dated as of September 27, 2010, among Inergy, L.P., Inergy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.1 to Inergy, L.P. s Form 8-K filed on September 28, 2010) |
| *4.5 | First Supplemental Indenture and Amendment Subsidiary Guarantee, dated as of November 5, 2010, to the Indenture, dated as of September 27, 2010 (incorporated herein by reference to Exhibit 10.5 to Inergy, L.P. s Form 8-K filed on November 5, 2010) |

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| Exhibit Number | Description |
|---|---|
| *4.6 | Indenture, dated as of February 2, 2011, among Inergy, L.P., Inergy Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated herein by reference to Exhibit 4.3 to Inergy, L.P.  s Form 8-K filed on February 3, 2011) |
| *10.1 | Employment Agreement dated as of November 24, 2010 between Inergy GP, LLC and John J. Sherman (incorporated herein by reference to Exhibit 10.1 to Inergy, L.P.  s Form 10-K filed on November 29, 2010)**** |
| *10.2 | Second Amended and Restated Employment Agreement, dated as of February 1, 2010, between Inergy GP, LLC and Phillip L. Elbert (incorporated herein by reference to Exhibit 10.2 to Inergy, L.P.  s Form 10-Q filed on February 3, 2010)**** |
| *10.3 | Employment Agreement, dated as of October 1, 2007, between Inergy GP, LLC and William R. Moler (incorporated herein by reference to Exhibit 10.7 to Inergy L.P.  s Form 10-K filed on December 1, 2008)**** |
| *10.3A | First Amendment to Employment Agreement, dated as of November 25, 2009, between Inergy GP, LLC and  William R. Moler (incorporated herein by reference to Exhibit 10.7A to Inergy L.P.  s Form 10-K filed on November 30, 2009) |
| **10.4 | Employment Agreement, dated as of January 27, 2011 between Inergy GP, LLC and Laura L. Ozenberger**** |
| *10.5 | Amended and Restated Employment Agreement, dated as of February 1, 2010, between Inergy GP, LLC and R. Brooks Sherman, Jr. (incorporated by reference to Exhibit 10.1 to Inergy, L.P.  s Form 10-Q filed on February 3, 2010)**** |
| *10.6 | Inergy Long Term Incentive Plan (as amended and restated on August 14, 2008) (incorporated herein by reference to Exhibit 10.1 to Inergy, L.P.  s Form 8-K filed on August 18, 2008)**** |
| *10.7 | Form of Inergy, L.P.  s Restricted Unit Award Agreement (incorporated herein by reference to Exhibit 10.11 to Inergy, L.P.  s Form 10-K filed on November 29, 2007)**** |
| *10.8 | Amended and Restated Inergy Unit Purchase Plan (incorporated herein by reference to Exhibit 10.1 to Inergy L.P.  s Form 10-Q filed on February 13, 2004)**** |
| *10.9 | Form of Inergy, L.P.  s Unit Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to Inergy, L.P.  s Form 8-K filed on November 29, 2010))**** |
| *10.10 | Summary of Non-Employee Director Compensation(incorporated herein by reference to Exhibit 10.11 to Inergy, L.P.  s Form 10-K filed on November 29, 2010)**** |
| *10.11 | Amended and Restated Credit Agreement dated as of February 2, 2011among Inergy, L.P., lenders named therein and JPMorgan Chase Bank, N.A. as administrative agent (incorporated herein by reference to Exhibit 10.1 to Inergy, L.P.  s Form 8-K filed on February 3, 2011) |
| *10.12 | Amendment No. 1 to Amended and Restated Credit Agreement, dated as of July 28, 2011 among Inergy, L.P., lenders named therein and JPMorgan Chase Bank, N.A. as administrative agent(incorporated herein by reference to Exhibit 10.1 to Inergy, L.P.  s Form 8-K filed on August 1, 2011) |
| *10.13 | Equity Purchase Agreement, dated December 31, 2009, among Inergy Propane, LLC, Sterling Capital Partners, L.P., Sterling Capital Partners Gmbh & Co. KG and certain other parties (incorporated herein by reference to Exhibit 10.1 to Inergy, L.P.  s Form 8-K filed on December 31, 2009) |

| Exhibit Number | Description |
|---|---|
| **12.1 | Computation of ratio of earnings to fixed charges |
| *14.1 | Inergy s Code of Business Ethics and Conduct (incorporated herein by reference to Exhibit 14.1 to Inergy, L.P. s Form 8-K filed on December 23, 2003) |
| **21.1 | List of subsidiaries of Inergy, L.P. |
| **23.1 | Consent of Ernst & Young LLP |
| **31.1 | Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended |
| **31.2 | Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Rule 15d-14(a) of the Securities Exchange Act, as amended |
| **32.1 | Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| **32.2 | Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| ***101.INS | XBRL Instance Document |
| ***101.SCH | XBRL Taxonomy Extension Schema Document |
| ***101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| ***101.LAB | XBRL Taxonomy Extension Label Linkbase Document |
| ***101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| ***101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

* Previously filed
** Filed herewith
*** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections.
**** Management contracts or compensatory plans or arrangements required to be identified by Item 15(a).

(b) Exhibits.
See exhibits identified above under Item 15(a)3.

(c) Financial Statement Schedules.
See financial statement schedules identified above under Item 15(a)2.

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**Inergy, L.P. and Subsidiaries**

**Consolidated Financial Statements**

**September 30, 2011 and 2010 and each of the**

**Three Years in the Period Ended**

**September 30, 2011**

**Contents**

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Unitholders of Inergy, L.P.

We have audited the accompanying consolidated balance sheets of Inergy, L.P. and Subsidiaries (the Company) as of September 30, 2011 and 2010, and the related consolidated statements of operations, partners capital and cash flows for each of the three years in the period ended September 30, 2011. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Inergy, L.P. and Subsidiaries at September 30, 2011 and 2010, and the consolidated results of their operations and their cash flows for each of the three years in the period ended September 30, 2011, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 10 to the consolidated financial statements, the accompanying consolidated financial statements have been retrospectively adjusted to give effect to the adoption of certain provisions of Financial Accounting Standards Board Accounting Standards Codification Subtopic 810-10 ( 810-10 ), Consolidations, relating to the presentation of non-controlling interests.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Inergy, L.P. and Subsidiaries internal control over financial reporting as of September 30, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commissions and our report dated November 15, 2011, expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Kansas City, Missouri

November 15, 2011

**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Unitholders of Inergy, L.P.

We have audited Inergy, L.P. and Subsidiaries internal control over financial reporting as of September 30, 2011, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Inergy, L.P. and Subsidiaries management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management s Report on Internal Control over Financial Reporting, management s assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of its fiscal 2011 acquisitions, which are included in the 2011 consolidated financial statements of Inergy, L.P. and Subsidiaries and constituted $110.2 million of total assets as of September 30, 2011, and $72.4 million of revenues for the year then ended. Our audit of internal control over financial reporting of Inergy, L.P. and Subsidiaries also did not include an evaluation of the internal control over financial reporting of those fiscal 2011 acquisitions.

In our opinion, Inergy, L.P. and Subsidiaries maintained, in all material respects, effective internal control over financial reporting as of September 30, 2011, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the 2011 consolidated financial statements of Inergy, L.P. and Subsidiaries and our report dated November 15, 2011 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Kansas City, Missouri

November 15, 2011

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**Inergy, L.P. and Subsidiaries**

**Consolidated Balance Sheets**

*(in millions, except unit information)*

| | September 30, 2011 | September 30, 2010 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 11.5 | $ 144.4 |
| Restricted cash (*Note 2*) | | 588.0 |
| Accounts receivable, less allowance for doubtful accounts of $2.6 million and $3.2 million at September 30, 2011 and 2010, respectively | 167.7 | 108.0 |
| Inventories (*Note 4*) | 212.9 | 137.1 |
| Assets from price risk management activities | 17.1 | 22.5 |
| Prepaid expenses and other current assets | 18.2 | 15.5 |
| Total current assets | 427.4 | 1,015.5 |
| Property, plant and equipment (*Note 4*) | 2,617.4 | 1,695.2 |
| Less: accumulated depreciation | 588.0 | 445.1 |
| Property, plant and equipment, net | 2,029.4 | 1,250.1 |
| Intangible assets (*Note 4*): | | |
| Customer accounts | 413.6 | 408.0 |
| Other intangible assets | 163.8 | 160.5 |
| | 577.4 | 568.5 |
| Less: accumulated amortization | 193.6 | 162.1 |
| Intangible assets, net | 383.8 | 406.4 |
| Goodwill | 498.1 | 444.3 |
| Other assets | 2.2 | 1.5 |
| Total assets | $ 3,340.9 | $ 3,117.8 |
| **Liabilities and partners capital** | | |
| Current liabilities: | | |
| Accounts payable | $ 146.2 | $ 88.4 |
| Accrued expenses | 85.2 | 62.5 |
| Customer deposits | 52.0 | 56.8 |
| Liabilities from price risk management activities | 19.0 | 24.3 |
| Current portion of long-term debt (*Note 7*) | 7.4 | 29.6 |
| Total current liabilities | 309.8 | 261.6 |
| Long-term debt, less current portion (*Note 7*) | 1,845.6 | 1,661.1 |
| Other long-term liabilities | 19.3 | 14.3 |
| Deferred income taxes | 20.2 | 20.7 |
| Partners capital (*Note 10*): | | |
| Limited partner unitholders (119,147,858 and 36,303,699 common units issued and outstanding as of September 30, 2011 and 2010, respectively, and 12,165,499 and 11,568,560 Class B units issued and outstanding at September 30, 2011 and 2010, respectively) | 1,146.0 | 53.3 |
| Total Inergy, L.P. partners capital | 1,146.0 | 53.3 |

| | | |
|---|---|---|
| Interest of non-controlling partners in subsidiaries | | 1,106.8 |
| Total partners capital | 1,146.0 | 1,160.1 |
| Total liabilities and partners capital | $ 3,340.9 | $ 3,117.8 |

*The accompanying notes are an integral part of these consolidated financial statements.*

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**Inergy, L.P. and Subsidiaries**

**Consolidated Statements of Operations**

*(in millions, except unit and per unit data)*

| | Year Ended September 30, 2011 | 2010 | 2009 |
|---|---|---|---|
| Revenue: | | | |
| Propane | $ 1,461.9 | $ 1,272.4 | $ 1,124.4 |
| Other | 691.9 | 513.6 | 446.2 |
| | 2,153.8 | 1,786.0 | 1,570.6 |
| Cost of product sold (excluding depreciation and amortization as shown below): | | | |
| Propane | 1,044.0 | 862.9 | 737.4 |
| Other | 432.0 | 303.0 | 259.5 |
| | 1,476.0 | 1,165.9 | 996.9 |
| Expenses: | | | |
| Operating and administrative | 323.3 | 310.7 | 280.5 |
| Depreciation and amortization | 191.8 | 161.8 | 115.8 |
| Loss on disposal of assets | 8.2 | 11.5 | 5.2 |
| Operating income | 154.5 | 136.1 | 172.2 |
| Other income (expense): | | | |
| Interest expense, net | (113.5) | (91.5) | (70.5) |
| Early extinguishment of debt (*Note 7*) | (52.1) | | |
| Other income | 1.2 | 2.0 | 0.1 |
| Income (loss) before gain on issuance of units in subsidiary and income taxes | (9.9) | 46.6 | 101.8 |
| Gain on issuance of units in subsidiary *(Note 10)* | | | 8.0 |
| Provision for income taxes | 0.7 | 0.2 | 1.7 |
| Net income (loss) | (10.6) | 46.4 | 108.1 |
| Net (income) loss attributable to non-controlling partners | 28.2 | 15.4 | (51.0) |
| Net income attributable to partners | $ 17.6 | $ 61.8 | $ 57.1 |
| Partners interest information: | | | |
| Total limited partners interest in net income | $ 17.6 | $ 61.8 | $ 57.1 |
| Net income per limited partner unit: | | | |
| Basic | $ 0.17 | $ 1.73 | $ 1.62 |
| Diluted | $ 0.15 | $ 1.29 | $ 1.21 |
| Weighted-average limited partners units outstanding (*in thousands*): | | | |
| Basic | 105,732 | 35,726 | 35,197 |
| Dilutive units | 11,952 | 12,276 | 11,839 |
| Diluted | 117,684 | 48,002 | 47,036 |

*The accompanying notes are an integral part of these consolidated financial statements.*

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**Inergy, L.P. and Subsidiaries**

**Consolidated Statements of Partners Capital**

*(in millions)*

| | Common Unit Capital | Non-Controlling Partners | Total Partners Capital |
|---|---|---|---|
| Balance at September 30, 2008 | $ 36.9 | $ 572.2 | $ 609.1 |
| Net proceeds from the issuance of common units | | 201.2 | 201.2 |
| Net proceeds from common unit options exercised | 0.7 | 0.8 | 1.5 |
| Issuance of common units for acquisition | | 6.7 | 6.7 |
| Unit-based compensation charges | | 3.1 | 3.1 |
| Retirement of common units | | (0.7) | (0.7) |
| Distributions | (57.8) | (127.5) | (185.3) |
| Comprehensive income: | | | |
| Net income excluding gain on issuance of units in subsidiary | 49.1 | 51.0 | 100.1 |
| Gain on issuance of units in subsidiary | 8.0 | (8.0) | |
| Change in unrealized fair value on cash flow hedges | 3.6 | 32.7 | 36.3 |
| Comprehensive income | | | 136.4 |
| Balance at September 30, 2009 | 40.5 | 731.5 | 772.0 |
| Net proceeds from the issuance of common units | | 602.7 | 602.7 |
| Net proceeds from common unit options exercised | 6.2 | 2.8 | 9.0 |
| Unit-based compensation charges | | 4.8 | 4.8 |
| Acquisition of non-controlling interest | | (18.3) | (18.3) |
| Costs associated with the simplification of capital structure | (4.1) | (2.9) | (7.0) |
| Retirement of common units | | (0.1) | (0.1) |
| Distributions | (77.6) | (165.2) | (242.8) |
| Comprehensive income: | | | |
| Net income excluding gain on issuance of units in subsidiary | 61.8 | (15.4) | 46.4 |
| Gain on issuance of units in subsidiary | 27.1 | (27.1) | |
| Change in unrealized fair value on cash flow hedges | (0.6) | (6.0) | (6.6) |
| Comprehensive income | | | 39.8 |
| Balance at September 30, 2010 | 53.3 | 1,106.8 | 1,160.1 |
| Net proceeds from the issuance of common units | 311.4 | (0.2) | 311.2 |
| Net proceeds from common unit options exercised | 2.2 | 3.0 | 5.2 |
| Unit-based compensation charges | 4.4 | 1.4 | 5.8 |
| Acquisition of non-controlling interest | 1,032.9 | (1,032.9) | |
| Costs associated with the simplification of capital structure | (0.7) | (0.4) | (1.1) |
| Retirement of common units | (1.9) | | (1.9) |
| Distributions | (260.1) | (51.5) | (311.6) |
| Comprehensive income: | | | |
| Net income (loss) | 17.6 | (28.2) | (10.6) |
| Change in unrealized fair value on cash flow hedges | (13.1) | 2.0 | (11.1) |
| Comprehensive income | | | (21.7) |

| | | | |
|---|---|---|---|
| Balance at September 30, 2011 | $ 1,146.0 | $ | $ 1,146.0 |

*The accompanying notes are an integral part of these consolidated financial statements.*

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**Inergy, L.P. and Subsidiaries**

**Consolidated Statements of Cash Flows**

*(in millions)*

| | Year Ended September 30, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| **Operating activities** | | | |
| Net income (loss) | $ (10.6) | $ 46.4 | $ 108.1 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and depletion | 154.8 | 126.5 | 88.8 |
| Amortization | 37.0 | 35.3 | 27.0 |
| Amortization of deferred financing costs, swap premium and net bond discount | 7.4 | 7.3 | 5.2 |
| Unit-based compensation charges | 5.8 | 4.8 | 3.1 |
| Provision for doubtful accounts | 3.7 | 2.8 | 3.7 |
| Loss on disposal of assets | 8.2 | 11.5 | 5.2 |
| Gain on issuance of units in subsidiary | | | (8.0) |
| Deferred income taxes | (0.5) | (0.3) | 0.4 |
| Early extinguishment of debt | 12.7 | | |
| Changes in operating assets and liabilities, net of effects from acquisitions: | | | |
| Accounts receivable | (59.9) | 1.9 | 41.4 |
| Inventories | (75.4) | (33.4) | 3.9 |
| Prepaid expenses and other current assets | (1.2) | 7.6 | 1.6 |
| Other assets (liabilities) | (1.9) | 0.4 | 0.1 |
| Accounts payable and accrued expenses | 46.1 | (21.1) | (33.1) |
| Customer deposits | (4.8) | (5.8) | (27.5) |
| Net assets (liabilities) from price risk management activities | (7.0) | (10.3) | 18.0 |
| Net cash provided by operating activities | 114.4 | 173.6 | 237.9 |
| **Investing activities** | | | |
| Acquisitions, net of cash acquired | (824.5) | (253.0) | (12.1) |
| Purchases of property, plant and equipment | (180.6) | (92.3) | (224.8) |
| Proceeds from sale of assets | 26.5 | 6.9 | 7.0 |
| Investment in bond offering escrow account | 588.0 | (588.0) | |
| Other | | | (0.7) |
| Net cash used in investing activities | (390.6) | (926.4) | (230.6) |

*The accompanying notes are an integral part of these consolidated financial statements.*

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**Inergy, L.P. and Subsidiaries**

**Consolidated Statements of Cash Flows (continued)**

*(in millions)*

| | Year Ended September 30, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| **Financing activities** | | | |
| Proceeds from the issuance of long-term debt | $ 1,971.8 | $ 1,555.7 | $ 884.9 |
| Principal payments on long-term debt | (1,824.1) | (1,003.2) | (909.1) |
| Distributions | (260.1) | (77.6) | (57.8) |
| Distributions paid to non-controlling partners | (51.5) | (165.2) | (127.5) |
| Acquisition of minority interest | | (18.3) | |
| Payments for deferred financing costs | (20.5) | (23.6) | (5.5) |
| Costs associated with the simplification of capital structure | (1.1) | (2.3) | |
| Net proceeds from issuance of common units | 311.2 | 602.7 | 201.2 |
| Retirement of common units | (1.9) | (0.1) | (0.7) |
| Net proceeds from common unit options exercised | 5.2 | 9.0 | 1.5 |
| Proceeds from swap settlement | 14.3 | 8.4 | |
| Net cash provided by (used in) financing activities | 143.3 | 885.5 | (13.0) |
| Net increase (decrease) in cash | (132.9) | 132.7 | (5.7) |
| Cash at beginning of period | 144.4 | 11.7 | 17.4 |
| Cash at end of period | $ 11.5 | $ 144.4 | $ 11.7 |
| **Supplemental disclosure of cash flow information** | | | |
| Cash paid during the period for interest | $ 89.8 | $ 84.0 | $ 66.7 |
| Cash paid during the year for income taxes | $ 0.5 | $ 0.8 | $ 1.7 |
| **Supplemental schedule of noncash investing and financing activities** | | | |
| Additions to intangible assets through the issuance of noncompetition agreements and notes to former owners of businesses acquired | $ 4.1 | $ 6.4 | $ 4.3 |
| Net change to property, plant and equipment through accounts payable and accrued expenses | $ 19.6 | $ (6.9) | $ (6.2) |
| Change in the fair value of interest rate swap liability and related long-term debt | $ 0.5 | $ (5.6) | $ 3.7 |
| Acquisitions, net of cash acquired: | | | |
| Current assets | $ 5.5 | $ 27.4 | $ 0.7 |
| Property, plant and equipment | 768.4 | 81.3 | 79.4 |
| Intangible assets, net | 8.7 | 146.6 | 8.7 |
| Goodwill (*Note 3*) | 53.8 | 49.9 | (68.8) |
| Other assets | 1.0 | 0.1 | |
| Current liabilities | (12.9) | (52.3) | (1.2) |
| Issuance of equity | | | (6.7) |
| Total acquisitions, net of cash acquired | $ 824.5 | $ 253.0 | $ 12.1 |

*The accompanying notes are an integral part of these consolidated financial statements.*

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements**

**Note 1. Partnership Organization and Basis of Presentation**

**Organization**

On August 7, 2010, Inergy, L.P. ( Inergy ) and Inergy Holdings, L.P. ( Holdings ) entered into an Agreement and Plan of Merger, which was amended and restated by the First Amended and Restated Agreement and Plan of Merger, dated as of September 3, 2010, as part of a plan to simplify the capital structures of Inergy and Holdings (the Merger Agreement ). Pursuant to the steps contemplated by the Merger Agreement (the Simplification Transaction ), Holdings merged into a wholly owned subsidiary of its general partner (the Merger ) and the outstanding common units in Holdings were cancelled. The Merger closed on November 5, 2010, resulting in Holdings unitholders receiving 0.77 Inergy units for each Holdings unit. Cash was paid to Holdings unitholders in lieu of any fractional units that resulted from the exchange. As a result of the closing, Holdings common units discontinued trading on the New York Stock Exchange as of the close of business on November 5, 2010. Holdings continues to own the general partner of Inergy subsequent to the Merger.

The Simplification Transaction was accounted for in accordance with Accounting Standards Codification ( ASC ) 810. Under ASC 810, the exchange of Holdings units for Inergy units was accounted for as a Holdings equity issuance and Holdings was the surviving entity. Although Holdings was the surviving entity for accounting purposes, Inergy was the surviving entity for legal purposes as provided for by the Merger Agreement; consequently, the name on these financial statements was changed from Inergy Holdings, L.P. to Inergy, L.P.

Historically, Holdings ownership of Inergy s general partner, Inergy GP, LLC ( Inergy GP ), provided Holdings with an approximate 0.6% general partner interest in Inergy. Holdings also owned an approximate 6.0% limited partner interest in Inergy at September 30, 2010.

Because of the changes that the Simplification Transaction has had on these financial statements and Inergy s organizational structure, and because the nature of the pre-simplification and post-simplification Inergy entities are significantly different, these notes to consolidated financial statements refer to specific Inergy entities, with Inergy, L.P. prior to the simplification referred to as Holdings and after the simplification as Inergy , and the controlled operating subsidiary of Inergy, L.P. prior to the Merger is referred to as Inergy . References to the Company or Inergy in the footnotes related to the policies and procedures of Inergy, L.P. refer to Inergy, L.P. subsequent to the simplification. Other references to the Company or we , our and us throughout the footnotes refer to the controlled subsidiary of Inergy, L.P. prior to the simplification if the timing of the statement is prior to November 5, 2010, and to Inergy, L.P. subsequent to the simplification if the timing of the statement is subsequent to November 5, 2010. The operating activities of the Inergy, L.P. controlled subsidiary prior to the Merger and Inergy, L.P. subsequent to the Merger are identical.

**Inergy Midstream**

On August 9, 2011, we announced our intention to file a registration statement with the Securities and Exchange Commission ( SEC ) for the initial public offering ( IPO ) of a minority interest of a new master limited partnership formed to initially own and operate our Northeast natural gas and natural gas liquids ( NGL ) midstream storage and transportation business. We intend to use all cash proceeds received in the IPO to repay indebtedness.

**Nature of Operations**

Inergy s financial statements reflect two operating and reportable segments: propane operations and midstream operations. Inergy s propane operations include propane sales to end users, the sale of propane-related appliances and service work for propane-related equipment, the sale of distillate products and wholesale distribution of

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

propane and marketing and price risk management services to other users, retailers and resellers of propane. Inergy s midstream operations include storage of natural gas and natural gas liquids for third parties, fractionation of natural gas liquids, processing of natural gas, distribution of natural gas liquids and the production and sale of salt.

**Principles of Consolidation**

The accompanying consolidated financial statements include the accounts of Inergy, L.P., its wholly owned subsidiaries, Inergy Propane, LLC ( Inergy Propane ), Inergy Midstream, LLC ( Inergy Midstream , and together with Inergy Propane, the Operating Companies ), Inergy Partners, LLC ( Partners ), IPCH Acquisition Corp. ( IPCHA ) and Inergy Finance Corp. All significant intercompany transactions, including distribution income, and balances have been eliminated in consolidation.

**Note 2. Summary of Significant Accounting Policies**

**Financial Instruments and Price Risk Management**

Inergy utilizes certain derivative financial instruments to (i) manage its exposure to commodity price risk, specifically, the related change in the fair value of inventories, as well as the variability of cash flows related to forecasted transactions; (ii) ensure adequate physical supply of commodity will be available; and (iii) manage its exposure to interest rate risk associated with its fixed rate senior notes and its floating rate term loan. Inergy records all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of these derivative financial instruments are recorded either through current earnings or as other comprehensive income, depending on the type of transaction.

Inergy is party to certain commodity derivative financial instruments that are designated as hedges of selected inventory positions, and qualify as fair value hedges. Inergy is also periodically party to certain interest rate swap agreements designed to manage interest rate risk exposure. Inergy s overall objective for entering into fair value hedges is to manage its exposure to fluctuations in commodity prices and changes in the fair market value of its inventories and fixed rate borrowings. The commodity derivatives are recorded at fair value on the consolidated balance sheets as price risk management assets or liabilities and the related change in fair value is recorded to earnings in the current period as cost of product sold. The interest rate derivatives are recorded at fair value on the balance sheets in other assets or liabilities and the related change in fair value is recorded to earnings in the current period as interest expense.

Any ineffective portion of the fair value hedges is recognized as cost of product sold in the current period. Inergy recognized a $1.8 million, $0.4 million and $0.2 million net gain in the years ended September 30, 2011, 2010 and 2009, respectively, related to the ineffective portion of its fair value hedging instruments. In addition, for the year ended September 30, 2011, Inergy recognized no gain, and for the years ended September 30, 2010 and 2009, Inergy recognized a net loss of $0.1 million related to the portion of fair value hedging instruments that it excluded from its assessment of hedge effectiveness.

Inergy also enters into derivative financial instruments that qualify as cash flow hedges, which hedge the exposure of variability in expected future cash flows predominantly attributable to forecasted purchases to supply fixed price sale contracts and forecasted interest payments on our term loan. These derivatives are recorded on the balance sheet at fair value as price risk management assets or liabilities. The effective portion of the gain or loss on these cash flow hedges is recorded in other comprehensive income in partner s capital and reclassified into earnings in the same period in which the hedge transaction affects earnings. In certain situations under the rules, the ineffective portion of the gain or loss is recognized as cost of product sold in the current period.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

Accumulated other comprehensive income (loss) was $(6.7) million and $4.4 million at September 30, 2011 and 2010, respectively. Included in accumulated other comprehensive income (loss) was $(2.4) million attributable to commodity instruments and $(4.3) million attributable to interest rate swaps. Approximately $(2.0) million is expected to be reclassified to earnings from other comprehensive income over the next twelve months.

Inergy s policy is to offset fair value amounts of derivative instruments and cash collateral paid or received with the same counterparty under a master netting arrangement.

The cash flow impact of derivative financial instruments is reflected as cash flows from operating activities in the consolidated statements of cash flows.

**Revenue Recognition**

Sales of propane, other liquids and salt are recognized at the time product is shipped or delivered to the customer depending on the sales terms. Gas processing and fractionation fees are recognized upon delivery of the product. Revenue from the sale of propane appliances and equipment is recognized at the time of delivery. Revenue from repairs and maintenance is recognized upon completion of the service. Revenue from storage contracts is recognized during the period in which storage services are provided.

**Expense Classification**

Cost of product sold consists of tangible products sold including all propane and other natural gas liquids, salt and all propane related appliances, as well as certain direct costs incurred in providing storage services. Operating and administrative expenses consist of all expenses incurred by Inergy other than those described above in cost of product sold and depreciation and amortization. Certain of Inergy s operating and administrative expenses and depreciation and amortization are incurred in the distribution of the product sales and storage sale but are not included in cost of product sold. These amounts were $209.3 million, $176.3 million and $134.6 million during the years ended September 30, 2011, 2010 and 2009, respectively.

**Credit Risk and Concentrations**

Inergy is both a retail and wholesale supplier of propane gas. Inergy generally extends unsecured credit to its wholesale customers in the United States and Canada. In addition, Inergy collects margin payments from its customers to mitigate risk. Credit is generally extended to retail customers for the delivery of propane into Company and customer owned propane gas storage tanks. Provisions for doubtful accounts receivable are based on specific identification and historical collection results and have generally been within management s expectations. Account balances are charged off against the reserve when it is anticipated that the receivable will not be collected. The balance is considered past due or delinquent based on contractual terms.

Inergy enters into netting agreements with certain wholesale customers to mitigate the Company s credit risk. Realized gains and losses reflected in the Company s receivables and payables are reflected at a net balance to the extent a netting agreement is in place and the Company intends to settle on a net basis. Unrealized gains and losses reflected in the Company s assets and liabilities from price risk management activities are reflected on a net basis to the extent a netting agreement is in place.

One supplier, BP Amoco Corp., accounted for 14% of propane purchases during the past fiscal year. No other single supplier accounted for more than 10% of propane purchases in the current year.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

No single customer represented 10% or more of consolidated revenues. In addition, nearly all of Inergy s revenues are derived from sources within the United States, and all of its long-lived assets are located in the United States.

**Use of Estimates**

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amount of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the year. Actual results could differ from those estimates.

**Inventories**

Inventories for retail operations, which mainly consist of propane gas and other liquids, are stated at the lower of cost or market and are computed using the average cost method. Wholesale propane and other liquids inventories are designated under a fair value hedge program and are consequently marked to market. Propane and other liquids inventories being hedged and carried at market value at September 30, 2011 and 2010, amount to $147.7 million and $82.6 million, respectively. Inventories for midstream operations are stated at the lower of cost or market and are computed predominantly using the average cost method.

**Shipping and Handling Costs**

Shipping and handling costs are recorded as part of cost of product sold at the time product is shipped or delivered to the customer except as discussed in Expense Classification.

**Property, Plant and Equipment**

Property, plant and equipment are stated at cost. Depreciation is computed by the straight-line method over the estimated useful lives of the assets, as follows:

| | Years |
|---|---|
| Buildings, land and improvements | 25 70 |
| Office furniture and equipment | 3 10 |
| Vehicles | 5 10 |
| Tanks and plant equipment | 5 30 |
| Reserve gas | 10 |

Salt deposits are depleted on a unit of production method.

Inergy reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such events or changes in circumstances are present, a loss is recognized if the carrying value of the asset is in excess of the sum of the undiscounted cash flows expected to result from the use of the asset and its eventual disposition. An impairment loss is measured as the amount by which the carrying amount of the asset exceeds the fair value of the asset. Inergy identified certain tanks in which the carrying amount exceeded the fair value due to the Company s plan to sell the tanks. See Note 4 for a discussion of assets held for sale at September 30, 2011 and 2010.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Identifiable Intangible Assets**

The Company has recorded certain identifiable intangible assets, including customer accounts, covenants not to compete, trademarks and deferred financing costs. Customer accounts, covenants not to compete and trademarks have arisen from acquisitions. Deferred financing costs represent financing costs incurred in obtaining financing and are being amortized over the term of the related debt. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer s intent to do so.

Certain intangible assets are amortized on a straight-line basis over their estimated economic lives, as follows:

| | **Weighted-Average Life** *(years)* |
|---|---|
| Customer accounts | 15.4 |
| Covenants not to compete | 8.6 |
| Deferred financing costs | 6.2 |

Trademarks have been assigned an indefinite economic life and are not being amortized, but are subject to an annual impairment evaluation.

Estimated amortization, including amortization of deferred financing costs reported as interest expense, for the next five years ending September 30, is as follows (*in millions*):

| **Year Ending September 30,** | |
|---|---|
| 2012 | $ 41.8 |
| 2013 | 40.6 |
| 2014 | 38.0 |
| 2015 | 36.3 |
| 2016 | 32.9 |

**Goodwill**

Goodwill is recognized for various acquisitions as the excess of the cost of the acquisitions over the fair value of the related net assets at the date of acquisition. Goodwill is subject to at least an annual assessment for impairment by applying a fair-value-based test.

In connection with the goodwill impairment evaluation, the Company identified five reporting units. The carrying value of each reporting unit is determined by assigning the assets and liabilities, including the existing goodwill and intangible assets, to those reporting units as of the date of the evaluation on a specific identification basis. To the extent a reporting unit s carrying value exceeds its fair value, an indication exists that the reporting unit s goodwill may be impaired and the second step of the impairment test must be performed. In the second step, the implied fair value of the goodwill is determined by allocating the fair value to all of its assets (recognized and unrecognized) and liabilities to its carrying amount.

Inergy has completed the impairment test for each of its reporting units and determined that no impairment existed as of September 30, 2011.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Income Taxes**

Inergy is a publicly-traded master limited partnership. Partnerships are generally not subject to federal income tax, although publicly-traded partnerships are treated as corporations for federal income tax purposes and therefore are subject to federal income tax, unless the partnership generates at least 90% of its gross income from qualifying sources. If the qualifying income requirement is satisfied, the publicly-traded partnership will be treated as a partnership for federal income tax purposes. Inergy Sales and Service, Inc. ( Services ), a subsidiary of Inergy, does not generate at least 90% of its gross income from qualifying sources, and as such, federal and state income taxes are provided on the taxable income of Services. The earnings of the Company and its limited liability subsidiaries are included in the Federal and state income tax returns of the individual members or partners. However, legislation in certain states allows for taxation of partnerships, and as such, certain state taxes for Inergy have been included in the accompanying financial statements as income taxes due to the nature of the tax in those particular states. In addition, Federal and state income taxes are provided on the earnings of the subsidiaries incorporated as taxable entities (IPCHA and Services). The Company is required to recognize deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial reporting and tax basis of assets and liabilities using expected rates in effect for the year in which differences are expected to reverse.

Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax basis and the financial reporting basis of assets and liabilities and the taxable income allocation requirements under the partnership agreement.

**Sales Tax**

Inergy accounts for the collection and remittance of all taxes on a net tax basis. As a result, these amounts are not reflected in the consolidated statements of operations.

**Customer Deposits**

Customer deposits primarily represent cash received by Inergy from wholesale and retail customers for propane purchased under contract that will be delivered at a future date.

**Cash and Cash Equivalents**

Inergy defines cash equivalents as all highly liquid investments with maturities of three months or less when purchased.

**Restricted Cash**

The net proceeds from Inergy s September 2010 $600 million bond offering were placed in an escrow account pending the closing of the Tres Palacios acquisition. These funds were released from escrow in October 2010 in conjunction with the closing of the Tres Palacios acquisition.

**Computer Software Costs**

Inergy includes costs associated with the acquisition of computer software in property, plant and equipment. Inergy amortizes computer software costs on a straight-line basis over expected periods of benefit, which generally are five years.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

### Fair Value

Cash and cash equivalents, accounts receivable (net of reserve for doubtful accounts) and payables are carried at cost, which approximates fair value due to their liquid and short-term nature. As of September 30, 2011, the estimated fair value of the fixed-rate Senior Notes, based on available trading information, totaled $1,358.8 million compared with the aggregate principal amount at maturity of $1,445.1 million. The Company s credit agreement ( Credit Agreement ) consists of a $700 million revolving loan facility ( Revolving Loan Facility ) and a $300 million term loan facility ( Term Loan Facility ). The carrying value at September 30, 2011, of amounts outstanding under the Credit Agreement of $381.2 million approximate fair value due primarily to the floating interest rate associated with the Credit Agreement.

Assets and liabilities from price risk management are carried at fair value as discussed in Note 6. At September 30, 2011, the estimated fair value of assets from price risk management activities amounted to $17.1 million and liabilities from price risk management amounted to $19.0 million.

### Comprehensive Income (Loss)

Comprehensive income includes net income and other comprehensive income, which is solely comprised of unrealized gains and losses on derivative financial instruments. Accumulated other comprehensive income (loss) consists of the following (*in millions*):

| | Accumulated Other Comprehensive Income (Loss) |
|---|---|
| As of September 30, 2009 | $ 11.0 |
| Other Comprehensive income[(a)] | (6.6) |
| As of September 30, 2010 | 4.4 |
| Other Comprehensive income[(a)] | (11.1) |
| As of September 30, 2011 | $ (6.7) |

(a) Other comprehensive income (loss) includes a reclassification of $4.9 million and $11.8 million to net income during the years ended September 30, 2011 and 2010, respectively.

Inergy records the effective portion of the unrealized gains and losses on its derivative financial instruments that qualify as cash flow hedges as other comprehensive income.

### Income Per Unit

Inergy calculates basic net income per limited partner unit by dividing net income applicable to partners common interest by the weighted-average number of units outstanding. Diluted net income per limited partner unit is computed by dividing net income by the weighted-average number of units outstanding and the effect of dilutive units granted under the Long Term Incentive Plan and the Class B units.

### Accounting for Unit-Based Compensation

Inergy has a unit-based employee compensation plan and all share-based payments to employees, including grants of employee stock options, are recognized in the income statement based on their fair values.

The amount of compensation expense recorded by the Company during the years ended September 30, 2011, 2010 and 2009, was $5.8 million, $4.8 million and $3.1 million, respectively.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Segment Information**

There are certain accounting requirements that establish standards for reporting information about operating segments, as well as related disclosures about products and services, geographic areas and major customers. Further, they define operating segments as components of an enterprise for which separate financial information is available that is evaluated regularly by the chief operating decision maker in deciding how to allocate resources and assess performance. In determining its reportable segments, Inergy examined the way it organizes its business internally for making operating decisions and assessing business performance. See Note 13 for disclosures related to Inergy s propane and midstream segments.

**Recently Issued Accounting Pronouncements**

In June 2011 the FASB issued Accounting Standards Update No. 2011-05, Presentation of Comprehensive Income ( ASU 2011-05 ). Under ASU 2011-05, an entity has the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Under both options, an entity will be required to present each component of net income along with total net income, each component of other comprehensive income along with a total for other comprehensive income, and a total amount for comprehensive income. Furthermore, regardless of the presentation methodology elected, the entity will be required to present on the face of the financial statements reclassification adjustments for items that are reclassified from other comprehensive income to net income. The amendments contained in ASU 2011-05 do not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. The amendments also do not affect how earnings per share is calculated or presented. ASU 2011-05 is effective for the Company on October 1, 2012. The Company does not currently anticipate the adoption of ASU 2011-05 will impact comprehensive income, however it will require the Company to change its historical practice of showing these items within the Consolidated Statement of Partners Capital.

In January 2010, the FASB issued Accounting Standards Update No. 2010-06, Improving Disclosures about Fair Value Measurements ( ASU 2010-06 ), which is included in the ASC Topic 820 (Fair Value Measurements and Disclosures). ASU 2010-06 requires new disclosures on the amount and reason for transfers in and out of Level 1 and Level 2 fair value measurements. ASU 2010-06 also requires disclosure of activities, including purchases, sales, issuances and settlements within the Level 3 fair value measurements and clarifies existing disclosure requirements on levels of disaggregation and disclosures about inputs and valuation techniques. The Company has previously adopted the new disclosures for transfers in and out of Level 1 and Level 2. The new disclosures for Level 3 are effective for fiscal years beginning after December 15, 2010. The Company does not currently anticipate that the adoption of the Level 3 disclosure requirements of ASU 2010-06 will result in a material change to the financial statements.

**Note 3. Acquisitions**

On October 14, 2010, Inergy completed the acquisition of Tres Palacios Gas Storage LLC ( Tres Palacios ), which owns and operates a natural gas storage facility located in Matagorda County, Texas. Tres Palacios is a high deliverability, salt dome natural gas storage facility with approximately 38.4 Bcf of Federal Energy Regulatory Commission ( FERC ) certificated working gas capacity (Caverns 1-3). The facility is potentially expandable by an additional 9.5 Bcf of working gas capacity, which Inergy expects to place in service in 2015 (Cavern 4).

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the acquisition date (*in millions*):

| | October 14, 2010 |
|---|---|
| Accounts receivable | $ 6.3 |
| Prepaid expenses and other current assets | 0.8 |
| Property, plant and equipment | 414.4 |
| Contractual rights | 266.9 |
| Other | 1.2 |
| Total identifiable assets acquired | 689.6 |
| Current liabilities | 12.4 |
| Total liabilities assumed | 12.4 |
| Net identifiable assets acquired | 677.2 |
| Goodwill | 45.3 |
| Net assets acquired | $ 722.5 |

The $45.3 million of goodwill has been assigned to the midstream operations segment.

Tres Palacios leases the surface and subsurface rights necessary to operate and expand the storage facility under an operating lease that expires on December 31, 2037, which is subject to automatic renewal for two 20-year extension periods unless Tres Palacios elects not to extend the term of the lease. The lease payments vary based on the FERC-certificated working gas capacity of the caverns which are in service as well as an incremental payment for physical volumes of gas injected and / or withdrawn from the caverns in service. Based on its current estimates, which assumes Cavern 4 will be in service during the fourth calendar quarter of 2015, Tres Palacios anticipates that the contractual obligation as of September 30, 2011, to be the following (in millions, excluding the above mentioned incremental payments as future volumes are currently unknown):

| Total | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|
| $ 403.4 | $11.4 | $23.5 | $29.0 | $339.5 |

The following represents the pro forma consolidated statements of operations as if Tres Palacios had been included in the consolidated results of the Company for the year ended September 30, 2010 (*unaudited, in millions*):

| | Pro Forma Consolidated Statements of Operations Year Ended September 30, 2010 |
|---|---|
| Revenue | $ 1,841.7 |
| Net income | $ 35.9 |

These amounts have been calculated after applying the Company s accounting policies and adjusting the results of Tres Palacios to reflect the depreciation that would have been charged assuming the preliminary fair value adjustments to property, plant and equipment and intangible assets had been made at the beginning of the respective period. The net income was further adjusted to give effect to the impact of the interest expense associated with the September 2010 bond offering that was utilized to finance a portion of the Tres Palacios acquisition.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

Revenue and net loss (including an allocation of intercompany interest expense) generated by Tres Palacios subsequent to the Company s acquisition on October 14, 2010, amounted to $46.0 million and $15.6 million, respectively.

On June 2, 2011, Tres Palacios entered into a binding term sheet to amend and supplement various terms and conditions of its operating lease. Among other things, Tres Palacios obtained the contractual right to store natural gas liquids in certain caverns located on the leased premises, as well as a right of first refusal over caverns developed in the future for the storage of natural gas liquids.

On October 19, 2010, Inergy completed the acquisition of the propane assets of Schenck Gas Services, LLC ( Schenck ), located in East Hampton, New York.

On November 15, 2010, Inergy completed the acquisition of the propane assets of Pennington Energy Corporation ( Pennington ), headquartered in Morenci, Michigan.

On July 13, 2011, Inergy closed on its acquisition of the Seneca Lake natural gas storage facility and two related pipelines from NYSEG. The natural gas storage facility and its West lateral were acquired by ASC and are subject to FERC jurisdiction. The East pipeline was acquired by Inergy Pipeline East, LLC and is subject to light-handed regulation by the NYPSC.

The purchase price allocations for the Seneca Lake acquisition has been prepared on a preliminary basis pending final asset valuation and asset rationalization, and changes are expected when additional information becomes available. Changes to reflect final asset valuation of prior fiscal year acquisitions have been included in the Company s consolidated financial statements but are not material.

The operating results for these acquisitions are included in the consolidated results of operations from the dates of acquisition through September 30, 2011.

As a result of the fiscal 2011 acquisitions, the Company acquired $53.4 million of goodwill and $9.7 million of intangible assets, consisting of the following (*in millions*):

| | |
|---|---|
| Customer accounts | $ 5.7 |
| Noncompetition agreements | 4.0 |
| Total intangible assets | $ 9.7 |

The amounts provided above relate solely to acquisitions that closed in fiscal 2011.

The weighted-average amortization period of amortizable intangible assets acquired during the year ended September 30, 2011, is approximately eleven years.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Note 4. Certain Balance Sheet Information**

**Inventories**

Inventories consisted of the following at September 30, 2011 and 2010, respectively (*in millions*):

| | September 30, 2011 | September 30, 2010 |
|---|---|---|
| Propane gas and other liquids | $ 195.4 | $ 121.0 |
| Appliances, parts, supplies and other | 17.5 | 16.1 |
| Total inventory | $ 212.9 | $ 137.1 |

**Property, Plant and Equipment**

Property, plant and equipment consisted of the following at September 30, 2011 and 2010, respectively (*in millions*):

| | September 30, 2011 | September 30, 2010 |
|---|---|---|
| Tanks and plant equipment | $ 1,097.8 | $ 937.9 |
| Buildings, land and improvements | 913.8 | 385.9 |
| Vehicles | 124.1 | 122.5 |
| Construction in process | 272.6 | 104.4 |
| Reserve gas | 132.1 | 69.8 |
| Salt deposits | 41.6 | 41.6 |
| Office furniture and equipment | 35.4 | 33.1 |
| | 2,617.4 | 1,695.2 |
| Less: accumulated depreciation | 588.0 | 445.1 |
| Total property, plant and equipment, net | $ 2,029.4 | $ 1,250.1 |

Depreciation expense totaled $154.6 million, $126.3 million and $88.6 million for the years ended September 30, 2011, 2010 and 2009, respectively. Depletion expense totaled $0.2 million for the years ended September 30, 2011, 2010 and 2009.

The tanks and plant equipment balances above include tanks owned by the Company that reside at customer locations. The leases associated with these tanks are accounted for as operating leases. These tanks have a value of $460.2 million with an associated accumulated depreciation balance of $121.3 million at September 30, 2011.

At September 30, 2011 and 2010, the Company capitalized interest of $16.2 million and $6.4 million, respectively, related to certain midstream asset expansion projects.

The property, plant and equipment balances above at September 30, 2011 and 2010, include $6.5 million and $4.4 million, respectively, of propane operations assets deemed held for sale. These assets consist primarily of tanks deemed to be excess, redundant or underperforming assets. In fiscal 2011 and 2010, these assets were identified primarily as a result of losses due to disconnecting customer installations of less profitable accounts due to low margins, poor payment history or low volume usage and customers who have chosen to switch suppliers. As a result, the carrying value of these assets was reduced to their estimated recoverable value less

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

anticipated disposition costs, resulting in losses of $11.1 million, $9.7 million and $4.9 million for the years ended September 30, 2011, 2010 and 2009, respectively. These losses are included as components of operating income as losses on disposal of assets. When aggregated with other realized gains/losses, such amounts totaled $8.2 million, $11.5 million and $5.2 million, respectively.

**Intangible Assets**

Intangible assets consist of the following at September 30, 2011 and 2010, respectively (*in millions*):

| | September 30, | |
|---|---|---|
| | 2011 | 2010 |
| Customer accounts | $ 413.6 | $ 408.0 |
| (accumulated amortization customer accounts) | (134.0) | (107.3) |
| Covenants not to compete | 83.4 | 79.4 |
| (accumulated amortization covenants not to compete) | (50.3) | (40.7) |
| Deferred financing and other costs | 49.5 | 50.2 |
| (accumulated amortization deferred financing costs) | (9.3) | (14.1) |
| Trademarks | 30.9 | 30.9 |
| Total intangible assets, net | $ 383.8 | $ 406.4 |

Amortization and interest expense associated with the above described intangible assets for the years ended September 30, 2011, 2010 and 2009, amounted to $43.4 million, $40.3 million and $30.3 million, respectively.

**Note 5. Risk Management**

The Company is exposed to certain market risks related to its ongoing business operations. These risks include exposure to changing commodity prices as well as fluctuations in interest rates. The Company utilizes derivative instruments to manage its exposure to fluctuations in commodity prices, which is discussed more fully below. The Company also periodically utilizes derivative instruments to manage its exposure to fluctuations in interest rates, which is discussed more fully in Note 7. Additional information related to derivatives is provided in Note 2 and Note 6.

**Commodity Derivative Instruments and Price Risk Management**

*Risk Management Activities*

Inergy sells propane and other commodities to energy related businesses and may use a variety of financial and other instruments including forward contracts involving physical delivery of propane. Inergy will enter into offsetting positions to hedge against the exposure its customer contracts create. Inergy does not designate these instruments as hedging instruments. These instruments are marked to market with the changes in the market value reflected in cost of product sold. Inergy attempts to balance its contractual portfolio in terms of notional amounts and timing of performance and delivery obligations. This balance in the contractual portfolio significantly reduces the volatility in cost of product sold related to these instruments. However, immaterial net unbalanced positions can exist or are established based on assessment of anticipated short-term needs or market conditions.

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

*Cash Flow Hedging Activity*

Inergy sells propane and heating oil to retail customers at fixed prices. Inergy will enter into derivative instruments to hedge a significant portion of its exposure to fluctuations in commodity prices as a result of selling the fixed price contracts. These instruments are identified and qualify to be treated as cash flow hedges. This accounting treatment requires the effective portion of the gain or loss on the derivative to be reported as a component of other comprehensive income and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

*Fair Value Hedging Activity*

Inergy will enter into derivative instruments to hedge its exposure to fluctuating commodity prices that results from maintaining its wholesale inventory. These instruments hedging wholesale inventory qualify to be treated as fair value hedges. This accounting treatment requires the fair value changes in both the derivative instruments and the hedged inventory to be recorded in cost of product sold.

A significant amount of inventory held in bulk storage facilities is hedged as it is not expected to be sold in the immediate future and is therefore exposed to fluctuations in commodity prices. Commodity inventory held at retail locations is not hedged as this inventory is expected to be sold in the immediate future and is therefore not exposed to fluctuations in commodity prices over an extended period of time.

**Commodity Price and Credit Risk**

*Notional Amounts and Terms*

The notional amounts and terms of the Company s derivative financial instruments include the following at September 30, 2011, and September 30, 2010 (*in millions*):

| | September 30, 2011 | | September 30, 2010 | |
|---|---|---|---|---|
| | Fixed Price Payor | Fixed Price Receiver | Fixed Price Payor | Fixed Price Receiver |
| Propane, crude and heating oil (*barrels*) | 10.1 | 10.6 | 6.2 | 5.8 |
| Natural gas (*MMBTU s*) | 0.1 | | | |

Notional amounts reflect the volume of transactions, but do not represent the amounts exchanged by the parties to the financial instruments. Accordingly, notional amounts do not reflect the Company s monetary exposure to market or credit risks.

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

*Fair Value of Derivative Instruments*

The following tables detail the amount and location on the Company s consolidated balance sheets and consolidated statements of operations related to all of its commodity derivatives (*in millions*):

| | Amount of Gain (Loss) Recognized in Net Income from Derivatives Year Ended September 30, | | Amount of Gain (Loss) Recognized in Net Income on Item Being Hedged Year Ended September 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Derivatives in fair value hedging relationships: | | | | |
| Commodity[(a)] | $ 8.3 | $ (3.0) | $ (6.5) | $ 3.4 |
| Debt[(b)] | 0.5 | 1.5 | (0.5) | (1.5) |
| Total fair value of derivatives | $ 8.8 | $ (1.5) | $ (7.0) | $ 1.9 |

| | Amount of Gain (Loss) Recognized in OCI on Effective Portion of Derivatives Year Ended September 30, | | Amount of Gain (Loss) Reclassified from OCI to Net Income Year Ended September 30, | | Amount of Gain (Loss) Recognized in Net Income on Ineffective Portion of Derivatives & Amount Excluded from Testing Year Ended September 30, | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 |
| Derivatives in cash flow hedging relationships: | | | | | | |
| Commodity[(c)] | $ (6.3) | $ 5.2 | $ 4.9 | $ 11.8 | $ | $ |
| Debt[(e)] | (4.3) | | | | | |
| | $ (10.6) | $ 5.2 | $ 4.9 | $ 11.8 | $ | $ |

| | Amount of Gain (Loss) Recognized in Net Income from Derivatives Year Ended September 30, | |
|---|---|---|
| | 2011 | 2010 |
| Derivatives not designated as hedging instruments: | | |
| Commodity[(d)] | $ 11.1 | $ 17.7 |

[a] The gain (loss) on both the derivative and the item being hedged are located in cost of product sold in the consolidated statements of operations.
[b] The gain (loss) on both the derivative and the item being hedged are located in interest expense in the consolidated statements of operations.
[c] The gain (loss) on the amount reclassified from OCI into income, the ineffective portion and the amount excluded from effectiveness testing are included in cost of product sold.
[d] The gain (loss) is recognized in cost of product sold.
[e] The gain (loss) on the amount reclassified from OCI into income, the ineffective portion and the amount excluded from effectiveness testing are included in interest expense.

All contracts subject to price risk had a maturity of twenty-two months or less; however, the majority of contracts expire within twelve months.

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

*Credit Risk*

Inherent in the Company s contractual portfolio are certain credit risks. Credit risk is the risk of loss from nonperformance by suppliers, customers or financial counterparties to a contract. Inergy takes an active role in managing credit risk and has established control procedures, which are reviewed on an ongoing basis. The Company attempts to minimize credit risk exposure through credit policies and periodic monitoring procedures as well as through customer deposits, letters of credit and entering into netting agreements that allow for offsetting counterparty receivable and payable balances for certain financial transactions, as deemed appropriate. The counterparties associated with assets from price risk management activities as of September 30, 2011 and 2010, were energy marketers and propane retailers, resellers and dealers.

Certain of the Company s derivative instruments have credit limits that require the Company to post collateral. The amount of collateral required to be posted is a function of the net liability position of the derivative as well as the Company s established credit limit with the respective counterparty. If the Company s credit rating were to change, the counterparties could require the Company to post additional collateral. The amount of additional collateral that would be required to be posted would vary depending on the extent of change in the Company s credit rating as well as the requirements of the individual counterparty. The aggregate fair value of all commodity derivative instruments with credit-risk-related contingent features that are in a liability position on September 30, 2011, is $6.7 million for which the Company has posted no collateral and $0.4 million of NYMEX margin deposit in the normal course of business. The Company has received collateral of $0.5 million in the normal course of business. All collateral amounts have been netted against the asset or liability with the respective counterparty.

**Note 6. Fair Value Measurements**

FASB Accounting Standards Codification Subtopic 820-10 ( 820-10 ) establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and US government treasury securities.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over the counter ( OTC ) forwards, options and physical exchanges.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

As of September 30, 2011, the Company held certain assets and liabilities that are required to be measured at fair value on a recurring basis. These included the Company s derivative instruments related to propane, heating oil, crude oil, natural gas liquids and interest rates as well as the portion of inventory that is hedged in a qualifying fair value hedge. The Company s derivative instruments consist of forwards, swaps, futures, physical exchanges and options.

Certain of the Company s derivative instruments are traded on the NYMEX. These instruments have been categorized as level 1.

The Company s derivative instruments also include OTC contracts, which are not traded on a public exchange. The fair values of these derivative instruments are determined based on inputs that are readily available in public markets or can be derived from information available in publicly quoted markets. These instruments have been categorized as level 2.

The Company s inventory that is the hedged item in a qualifying fair value hedge is valued based on prices quoted from observable sources and verified with broker quotes. This inventory has been categorized as level 2.

The Company s OTC options are valued based on an internal option model. The inputs utilized in the model are based on publicly available information as well as broker quotes. These options have been categorized as level 3.

The assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following table sets forth by level within the fair value hierarchy the Company s assets and liabilities that were accounted for at fair value on a recurring basis at September 30, 2011 and 2010, (*in millions*):

| | September 30, 2011 Fair Value of Derivatives | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Total** | **Designated as Hedges** | **Not Designated as Hedges** | **Netting Agreements[(a)]** | **Total** |
| **Assets** | | | | | | | | |
| Assets from price risk management | $ 1.2 | $ 23.4 | $ 4.0 | $ 28.6 | $ 8.8 | $ 19.8 | $ (11.5) | $ 17.1 |
| Inventory | | 147.7 | | 147.7 | | | | 147.7 |
| Interest rate swap | | 0.5 | | 0.5 | 0.5 | | | 0.5 |
| Total assets at fair value | $ 1.2 | $ 171.6 | $ 4.0 | $ 176.8 | $ 9.3 | $ 19.8 | $ (11.5) | $ 165.3 |
| **Liabilities** | | | | | | | | |
| Liabilities from price risk management | $ 0.9 | $ 15.4 | $ 2.7 | $ 19.0 | $ 5.4 | $ 13.6 | $ | $ 19.0 |
| Interest rate swap | | 4.3 | | 4.3 | 4.3 | | | 4.3 |
| Total liabilities at fair value | $ 0.9 | $ 19.7 | $ 2.7 | $ 23.3 | $ 9.7 | $ 13.6 | $ | $ 23.3 |

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

| | September 30, 2010 | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Fair Value of Derivatives | | | | | | | |
| | Level 1 | Level 2 | Level 3 | Total | Designated as Hedges | Not Designated as Hedges | Netting Agreements[a] | Total |
| **Assets** | | | | | | | | |
| Assets from price risk management | $ 0.6 | $ 26.6 | $ 1.5 | $ 28.7 | $ 6.6 | $ 22.1 | $ (6.2) | $ 22.5 |
| Inventory | | 82.6 | | 82.6 | | | | 82.6 |
| Total assets at fair value | $ 0.6 | $ 109.2 | $ 1.5 | $ 111.3 | $ 6.6 | $ 22.1 | $ (6.2) | $ 105.1 |
| **Liabilities** | | | | | | | | |
| Liabilities from price risk management | $ 0.7 | $ 16.7 | $ 1.9 | $ 19.3 | $ 6.9 | $ 12.4 | $ 5.0 | $ 24.3 |

(a) Amounts represent the impact of legally enforceable master netting agreements that allow the Company to settle positive and negative positions as well as cash collateral held or placed with the same counterparties.

For assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the period, 820-10 requires a reconciliation of the beginning and ending balances, separated for each major category of assets. The reconciliation is as follows (*in millions*):

| | Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Year Ended September 30, 2011 |
|---|---|
| Beginning balance | $ (0.4) |
| Beginning balance recognized during the period | 0.5 |
| Change in value of contracts executed during the period | 1.2 |
| Ending balance | $ 1.3 |

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Note 7. Long-Term Debt**

Long-term debt consisted of the following at September 30, 2011 and 2010, respectively (*in millions*):

| | September 30, 2011 | 2010 |
|---|---|---|
| Credit agreement: | | |
| Revolving loan facility | $ 81.2 | $ |
| Term loan facility | 300.0 | |
| Senior unsecured notes | 1,445.1 | 1,650.0 |
| Fair value hedge adjustment on senior unsecured notes | 0.5 | |
| Bond/swap premium | 13.8 | 10.4 |
| Bond discount | (5.3) | (16.0) |
| Obligations under noncompetition agreements and notes to former owners of businesses acquired | 17.7 | 21.8 |
| Holdings term loan | | 24.5 |
| Total debt | 1,853.0 | 1,690.7 |
| Less: current portion | 7.4 | 29.6 |
| Total long-term debt | $ 1,845.6 | $ 1,661.1 |

**Credit Agreement**

On November 24, 2009, Inergy entered into a secured credit facility ( Credit Agreement ) which provided borrowing capacity of up to $525 million in the form of a $450 million revolving general partnership credit facility ( General Partnership Facility ) and a $75 million working capital credit facility ( Working Capital Facility ). This facility was to mature on November 22, 2013. Borrowings under these secured facilities are available for working capital needs, future acquisitions, capital expenditures and other general partnership purposes, including the refinancing of existing indebtedness under the former credit facility.

On February 2, 2011, Inergy amended and restated the Credit Agreement to add a $300 million term loan facility (the Term Loan Facility ). The term loan matures on February 2, 2015, and bears interest, at Inergy s option, subject to certain limitations, at a rate equal to the following:

the Alternate Base Rate, which is defined as the higher of (i) the federal funds rate plus 0.50%; (ii) JP Morgan s prime rate; or (iii) the Adjusted LIBO Rate plus 1%; plus a margin varying from 1.00% to 2.25%; or

the Adjusted LIBO Rate, which is defined as the LIBO Rate plus a margin varying from 2.00% to 3.25%.

On July 28, 2011, Inergy further amended its amended and restated Credit Agreement to (i) raise the aggregate revolving commitment from $525 million to $700 million ( Revolving Loan Facility ) with the amount existing as a singular tranche, (ii) reduce the applicable rate on revolving loans and commitment fees, (iii) modify and refresh certain covenants and covenant baskets, and (iv) extend the maturity date from November 22, 2013 to July 28, 2016.

The Credit Agreement contains various affirmative and negative covenants and default provisions, as well as requirements with respect to the maintenance of specified financial ratios and limitations on making investments,

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

permitting liens and entering into other debt obligations. All borrowings under the Revolving Loan Facility bear interest, at Inergy s option, subject to certain limitations, at a rate equal to the following:

- the Alternate Base Rate, which is defined as the higher of (i) the federal funds rate plus 0.50%; (ii) JP Morgan s prime rate; or (iii) the Adjusted LIBO Rate plus 1%; plus a margin varying from 0.75% to 2.00%; or

- the Adjusted LIBO Rate, which is defined as the LIBO Rate plus a margin varying from 1.75% to 3.00%.

At September 30, 2011, the balance outstanding under the Credit Agreement was $381.2 million, of which $300.0 million was borrowed under the Term Loan Facility and $81.2 million under the Revolving Loan Facility. At September 30, 2010, there was no balance outstanding under the Credit Agreement. The interest rates of the Revolving Loan Facility are based on prime rate and LIBOR plus the applicable spreads, resulting in interest rates which were between 2.73% and 4.75% at September 30, 2011. The interest rate on the Term Loan Facility is based on LIBOR plus the applicable spread, resulting in an interest rate that was 3.23% at September 30, 2011. Availability under the Credit Agreement amounted to $575.3 million and $505.3 million at September 30, 2011 and 2010, respectively. Outstanding standby letters of credit under the Credit Agreement amounted to $43.5 million and $19.7 million at September 30, 2011 and 2010, respectively.

During each fiscal year beginning October 1, the outstanding balance of the Working Capital Facility must be reduced to $10.0 million or less for a minimum of 30 consecutive days during the period commencing March 1 and ending September 30 of each calendar year. This requirement was removed in the July 28, 2011 amendment with the Revolving Loan Facility now existing as a singular tranche facility.

At September 30, 2011, the Company was in compliance with the debt covenants in the Credit Agreement and senior unsecured notes.

**Senior Unsecured Notes**

**2014 Senior Notes**

In February and March 2011, $394.5 million in aggregate principal of the 2014 Senior Notes were tendered and the remaining $30.5 million were redeemed. Subsequent to the aforementioned transactions, there was no balance remaining on the 2014 Senior Notes at September 30, 2011.

**2016 Senior Notes**

In February and March 2011, $370.0 million in aggregate principal of the 2016 Senior Notes were tendered and the remaining $30.0 million were redeemed. Subsequent to the aforementioned transactions, there was no balance remaining on the 2016 Senior Notes at September 30, 2011.

**2015 Senior Notes**

On February 2, 2009, Inergy and its wholly-owned subsidiary, Inergy Finance Corp, issued $225 million aggregate principal amount of 8.75% senior unsecured notes due 2015 (the 2015 Senior Notes ) under Rule 144A to eligible purchasers. The 8.75% notes mature on March 1, 2015, and were issued at 90.191% of the principle amount to yield 11%.

The 2015 Senior Notes contain covenants similar to the Credit Agreement. Inergy used the net proceeds of the offering to repay outstanding indebtedness under the General Partnership facility. The 2015 Senior Notes

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

represent senior unsecured obligations of Inergy and rank *pari passu* in right of payment with all other present and future senior indebtedness of Inergy. The 2015 Senior Notes are fully, unconditionally, jointly and severally guaranteed by Inergy s wholly-owned domestic subsidiaries. Also, Inergy has no independent assets or operations, and subsidiaries not guaranteeing the indenture are minor. Accordingly, condensed consolidating financial information for the parent and subsidiaries is not presented.

On October 7, 2009, Inergy completed an offer to exchange its existing 8.75% 2015 Senior Notes for $225 million of 8.75% senior notes due 2015 (the 2015 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2015 Exchange Notes did not provide Inergy with any additional proceeds and satisfied Inergy s obligations under the registration rights agreement.

The 2015 Senior Notes are redeemable, at Inergy s option, in whole or in part, at any time on or after March 1, 2013, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| Year | Percentage |
|---|---|
| 2013 | 104.375% |
| 2014 and thereafter | 100.000% |

During the year ended September 30, 2011, $78.8 million in aggregate principal of these notes were redeemed utilizing the equity redemption feature of the indenture, an additional aggregate principal amount of $30.2 million was redeemed through tender and an additional aggregate principal amount of $21.0 million through purchases on the open markets.

**2018 Senior Notes**

On September 27, 2010, Inergy and its wholly-owned subsidiary, Inergy Finance Corp, issued $600 million aggregate principal amount of 7% senior unsecured notes due 2018 (the 2018 Senior Notes ) under Rule 144A to eligible purchasers. The 7% notes mature on October 1, 2018.

The 2018 Senior Notes contain covenants similar to the senior unsecured notes due 2015. Inergy used the net proceeds of the offering to fund part of the consideration for the Tres Palacios acquisition. The 2018 Senior Notes represent senior unsecured obligations of Inergy and rank *pari passu* in right of payment with all other present and future senior indebtedness of Inergy. The 2018 Senior Notes are fully, unconditionally, jointly and severally guaranteed by Inergy s wholly-owned domestic subsidiaries.

On June 2, 2011, Inergy completed an offer to exchange its existing 7% 2018 Senior Notes for $600 million of 7% senior notes due 2018 (the 2018 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2018 Exchange Notes did not provide Inergy with any additional proceeds and satisfied Inergy s obligations under the registration rights agreement.

The 2018 Senior Notes are redeemable, at Inergy s option, in whole or in part, at any time on or after October 1, 2014, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| Year | Percentage |
|---|---|
| 2014 | 103.500% |
| 2015 | 101.750% |
| 2016 and thereafter | 100.000% |

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**2021 Senior Notes**

On January 19, 2011, Inergy and its wholly-owned subsidiary, Inergy Finance Corp, issued $750 million aggregate principal amount of 6.875% senior unsecured notes due 2021 (the 2021 Senior Notes ) under Rule 144A to eligible purchasers. The 6.875% notes mature on August 1, 2021.

The 2021 Senior Notes contain covenants similar to the existing senior unsecured notes due 2015 and 2018. The 2021 Senior Notes represent senior unsecured obligations of Inergy and rank *pari passu* in right of payment with all other present and future senior indebtedness of Inergy. The 2021 Senior Notes are fully, unconditionally, jointly and severally guaranteed by Inergy s wholly-owned domestic subsidiaries.

On September 28, 2011, Inergy completed an offer to exchange its existing 6.875% 2021 Senior Notes for $750 million of 6.875% senior notes due 2021 (the 2021 Exchange Notes ) that are registered and do not carry transfer restrictions, registration rights and provisions for additional interest. The 2021 Exchange Notes did not provide Inergy with any additional proceeds and satisfied Inergy s obligations under the registration rights agreement.

The 2021 Senior Notes are redeemable, at Inergy s option, in whole or in part, at any time on or after August 1, 2016, in each case at the redemption prices described in the table below, together with any accrued and unpaid interest to the date of the redemption.

| **Year** | **Percentage** |
|---|---|
| 2016 | 103.438% |
| 2017 | 102.292% |
| 2018 | 101.146% |
| 2019 and thereafter | 100.000% |

Inergy used the net proceeds from the 2021 Senior Notes and the Term Loan Facility to: (1) fund its partial redemption of its 2015 Senior Notes; (2) fund its tender offers for portions of its 2014 Senior Notes, 2015 Senior Notes and 2016 Senior Notes; and (3) redeem all 2014 Senior Notes and 2016 Senior Notes not acquired in the tender offers related to such notes. The remaining net proceeds were used to repay outstanding borrowings under the General Partnership Facility and the Working Capital Facility and to provide additional working capital for general partnership purposes.

The indentures governing our senior notes restrict our ability to pay cash distributions. Before Inergy can pay a distribution to its unitholders, they must demonstrate that the fixed charge coverage ratio (as defined in the senior notes indentures) is at least 1.75 to 1.0. Inergy has met this coverage ratio every quarter.

**Interest Rate Swaps**

During fiscal year 2011, Inergy entered into eleven interest rate swaps, one of which is scheduled to mature in 2015 (notional amount of $25 million) and the remaining ten are scheduled to mature in 2018 (aggregate notional amount of $250 million). These swap agreements, which expire on the same date as the maturity date of the related senior unsecured notes and contain call provisions consistent with the underlying senior unsecured notes, require the counterparty to pay Inergy an amount based on the stated fixed interest rate due every six months. In exchange, Inergy is required to make semi-annual floating interest rate payments on the same dates to the counterparty based on an annual interest rate equal to the six-month LIBOR interest rate plus a spread of 6.705% on the swap maturing in 2015 and 3.25% to 3.46% on the swaps maturing in 2018 applied to the same aggregate

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

notional amount of $275 million. These swap agreements have been accounted for as fair value hedges. Amounts to be received or paid under the agreements are accrued and recognized over the life of the agreements as an adjustment to interest expense.

In August 2011, Inergy s ten interest rate swaps maturing in 2018 were terminated, and the Company received approximately $14.3 million in proceeds. These swaps had an aggregate notional amount of $250 million.

In addition, during fiscal year 2011, Inergy entered into six interest rate swap agreements scheduled to mature in 2015. These swap agreements, which expire on the same date as the maturity date of the related Term Loan Facility require Inergy to pay the counterparty an amount based on fixed rates from 0.84% to 2.43% due quarterly. In exchange, the counterparty is required to make quarterly floating interest rate payments on the same date to Inergy based on the three-month LIBOR applied to the same aggregate notional amount of $225 million. These swap agreements have been accounted for as cash flow hedges.

**Holdings Term Loan**

Prior to the completion of the Simplification Transaction, Holdings had a balance of $24.5 million on its term loan facility and no balance on its revolving bank facility. In conjunction with the Simplification Transaction, the above described debt balances were paid off in full and these facilities were terminated.

**Notes Payable and Other Obligations**

Non-interest bearing obligations due under noncompetition agreements and other note payable agreements consist of agreements between Inergy and the sellers of retail propane companies acquired from fiscal years 2003 through 2011 with payments due through 2020 and imputed interest ranging from 5.19% to 9.50%. Noninterest-bearing obligations consist of $21.8 million and $27.0 million in total payments due under agreements, less unamortized discount based on imputed interest of $4.2 million and $5.2 million at September 30, 2011 and 2010, respectively.

The aggregate amounts of principal to be paid on the outstanding long-term debt and notes payable during the next five years ending September 30 and thereafter are as follows (*in millions*):

| | Long-Term Debt and Notes Payable |
|---|---|
| 2012 | $ 7.4 |
| 2013 | 3.4 |
| 2014 | 2.7 |
| 2015 | 397.2 |
| 2016 | 79.4 |
| Thereafter | 1,362.9 |
| Total debt | $ 1,853.0 |

Accrued interest, classified in accrued expense on the consolidated balance sheets, at September 30, 2011 and 2010, was $32.5 million and $15.1 million, respectively.

**Note 8. Leases**

Inergy has certain noncancelable operating leases, mainly for office space and vehicles, the majority of which expire at various times over the next ten years. Certain of these leases contain terms that provide that the rental payment be indexed to published information.

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**Notes to Consolidated Financial Statements (Continued)**

Future minimum lease payments under noncancelable operating leases for the next five years ending September 30 and thereafter consist of the following (*in millions*):

| **Year Ending September 30,** | |
|---|---|
| 2012 | $ 23.9 |
| 2013 | 22.0 |
| 2014 | 20.9 |
| 2015 | 18.6 |
| 2016 | 18.6 |
| Thereafter | 343.5 |
| Total minimum lease payments | $ 447.5 |

Rent expense for operating leases for the years ended September 30, 2011, 2010 and 2009, totaled $25.4 million, $15.0 million and $11.7 million, respectively.

**Note 9. Income Taxes**

The provision for income taxes for the years ended September 30, 2011, 2010, and 2009 consisted of the following *(in millions)*:

| | **Year Ended September 30,** | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Current: | | | |
| Federal | $ 0.5 | $ 0.3 | $ 0.5 |
| State | 0.7 | 0.2 | 0.8 |
| Total current | 1.2 | 0.5 | 1.3 |
| Deferred: | | | |
| Federal | (0.5) | (0.3) | 0.4 |
| State | | | |
| Total deferred | (0.5) | (0.3) | 0.4 |
| Provision for income taxes | $ 0.7 | $ 0.2 | $ 1.7 |

The effective rate differs from the statutory rate because the income tax provision for the years ended September 30, 2011, 2010 and 2009, relates to taxable income of the corporations as discussed in Note 2.

Deferred income taxes related to IPCHA reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Components of the deferred income taxes at September 30, 2011 and 2010, are as follows *(in millions)*:

| | September 30, 2011 | 2010 |
|---|---|---|
| Deferred tax liabilities: | | |
| Basis difference in stock of acquired company | $ (20.2) | $ (20.7) |
| Total deferred tax liability | $ (20.2) | $ (20.7) |

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Note 10. Partners Capital**

**Common Unit Offerings**

In March 2009, Inergy issued 4,000,000 common units under its shelf registration statement, and in April 2009, the underwriters exercised their option to purchase 418,000 additional Inergy common units. Net proceeds from the aforementioned issuances amounted to $94.3 million.

In August 2009, Inergy issued 3,500,000 common units under its shelf registration statement, and in September 2009, the underwriters exercised their option to purchase 525,000 additional Inergy common units. Net proceeds from the aforementioned issuances amounted to $106.9 million.

In January 2010, Inergy issued 5,749,100 common units under its shelf registration statement, which included 749,100 common units issued as a result of the underwriters exercising their over-allotment provision. Net proceeds from the aforementioned issuances amounted to $199.8 million. Inergy used the net proceeds from this offering to repay outstanding indebtedness under its revolving General Partnership Facility, which was borrowed to fund the acquisitions of Liberty and MGS and to fund other capital expenditures in its midstream business.

In September 2010, Inergy issued 11,787,500 common units under its shelf registration statement, which included 1,537,500 common units issued as a result of the underwriters exercising their over-allotment provision. Net proceeds from the aforementioned issuances amounted to $402.9 million. Inergy utilized the proceeds from this offering to fund part of the consideration for the Tres Palacios acquisition.

On March 16, 2011, Inergy s new shelf registration statement (File No. 333-172312) was declared effective by the Securities and Exchange Commission for the periodic sale of up to $1.5 billion of common units, partnership securities and debt securities, or any combination thereof.

On June 6, 2011, Inergy issued 9,000,000 common units in a public offering. Inergy used the net proceeds from this offering to repay borrowings under its Revolving Loan Facility, to fund ongoing expansion projects in its midstream business and for general partnership purposes. Net proceeds from this issuance amounted to $311.2 million.

**Merger Conversion of Units**

All unit and per unit amounts have been revised to reflect the conversion of Holdings common units to 0.77 Inergy common units as a result of the Merger (discussed in Note 1), which closed on November 5, 2010.

**Class B Units**

The Class B units have similar rights and obligations of Inergy common units except that the units will pay distributions in kind rather than in cash for a certain period of time. Immediately after the payment of the Inergy, L.P. common unit distribution on November 14, 2011, approximately 6.6 million Class B units converted into common units of Inergy, L.P. and are entitled to receive cash distributions. During the three-month periods ended March 31, 2011, June 30, 2011 and September 30, 2011, Inergy distributed 195,652, 198,961 and 202,326 Class B units, respectively. For a complete description of the Class B units, please see the Third Amended and Restated Agreement of Limited Partnership of Inergy, filed on Form 8-K on November 5, 2010.

**Gain on Issuance of Units in Subsidiary**

Prior to the Merger (discussed in Note 1), Holdings recorded a gain of $8.0 million for fiscal 2009 to recognize the increase in value of its investment in Inergy resulting from the issuances of Inergy units, as permitted by FASB Accounting Standards Codification Subtopic 505-10 (originally issued as Staff Accounting Bulletin

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

No. 51 Accounting for Sales of Stock by a Subsidiary ). In accordance with the adoption of ASC 810-10, these gains on Inergy s issuances of units in fiscal 2010 are reflected in our consolidated statements of partners capital for the year ended September 30, 2010.

**Quarterly Distributions of Available Cash**

A summary of Holdings limited partner quarterly distributions for the three months ended December 31, 2010 and 2009, is presented below:

| | Three Months Ended December 31, 2010 | 2009 |
|---|---|---|
| Record date | October 22, 2010 | November 6, 2009 |
| Payment date | October 29, 2010 | November 13, 2009 |
| Per unit rate | $0.442 | $0.368 |
| Distribution amount (*in millions*) | $21.1 | $17.2 |

A summary of Inergy s limited partner quarterly distributions for the three months ended December 31, 2010 and 2009, is presented below:

| | Three Months Ended December 31, 2010 | 2009 |
|---|---|---|
| Record date | October 22, 2010 | November 6, 2009 |
| Payment date | October 29, 2010 | November 13, 2009 |
| Per unit rate | $0.705 | $0.675 |
| Distribution amount (*in millions*) | $76.1 | $55.2 |

A summary of the Company s post-simplification limited partner quarterly distribution for the nine months ended September 30, 2011 and 2010, is presented below:

**Nine Months Ended September 30, 2011**

| Record Date | Payment Date | Per Unit Rate | Distribution Amount (*in millions*) |
|---|---|---|---|
| February 7, 2011 | February 14, 2011 | $ 0.705 | $ 77.4 |
| May 6, 2011 | May 13, 2011 | $ 0.705 | 77.6 |
| August 5, 2011 | August 12, 2011 | $ 0.705 | 84.0 |
| | | | $ 239.0 |

**Nine Months Ended September 30, 2010[(a)]**

| Record Date | Payment Date | Per Unit Rate | Distribution Amount (*in millions*) |
|---|---|---|---|
| February 5, 2010 | February 12, 2010 | N/A | $ 61.2 |
| May 7, 2010 | May 14, 2010 | N/A | 62.5 |
| August 6, 2010 | August 13, 2010 | N/A | 64.5 |
| | | | $ 188.2 |

(a) In the Simplification Transaction, Holdings was the surviving entity for accounting purposes, for comparative purpose, the prior year amount represents the aggregate Holdings limited partner quarterly distributions of both Holdings and Inergy. The aggregate distribution amount excludes all distributions from Inergy to Holdings.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

On November 14, 2011, a quarterly distribution of $0.705 per limited partner unit was paid to unitholders of record on November 7, 2011, with respect to the fourth fiscal quarter of 2011, which totaled $83.9 million.

**Unit Purchase Plan**

Inergy s general partner sponsors a unit purchase plan for its employees and the employees of its affiliates. The unit purchase plan permits participants to purchase common units in market transactions from Inergy, the general partners or any other person. All purchases made have been in market transactions, although the plan allows Inergy to issue additional units. Inergy has reserved 100,000 units for purchase under the unit purchase plan. As determined by the compensation committee, the general partner may match each participant s cash base pay or salary deferrals by an amount up to 10% of such deferrals and have such amount applied toward the purchase of additional units. The general partner has also agreed to pay the brokerage commissions, transfer taxes and other transaction fees associated with a participant s purchase of common units. The maximum amount that a participant may elect to have withheld from his or her salary or cash base pay with respect to unit purchases in any calendar year may not exceed 10% of his or her base salary or wages for the year. Units purchased on behalf of a participant under the unit purchase plan generally are to be held by the participant for at least one year. To the extent a participant desires to sell or dispose of such units prior to the end of this one year holding period, the participant will be ineligible to participate in the unit purchase plan again until the one year anniversary of the date of such sale. The unit purchase plan is intended to serve as a means for encouraging participants to invest in common units. Units purchased through the unit purchase plan by Inergy and its employees for the fiscal years ended September 30, 2011, 2010 and 2009, were 13,821 units, 6,877 units, and 11,298 units, respectively. Prior to the Merger, Holdings general partner sponsored a similar plan for Inergy and its employees. Common units purchased through the Holdings unit purchase plan, reflective of the conversion to 0.77 Inergy common units, for the fiscal years ended September 30, 2010 and 2009, were 13,206 units and 12,717 units, respectively.

**Long-Term Incentive Plan**

Inergy s general partner sponsors the long-term incentive plan for its employees, consultants and directors and the employees of its affiliates that perform services for Inergy. The long-term incentive plan currently permits the grant of awards covering an aggregate of 11,914,786 common units, which can be granted in the form of unit options, phantom units and/or restricted units. With the exception of 56,000 unit options (exercise prices from $1.92 to $5.34) granted to non-executive employees in exchange for option grants made by the predecessor in fiscal 1999, all of which have been grandfathered into the long-term incentive plan and are presented as grants in the table below, all units granted under the plan will vest in accordance with the Unit Option Agreements, which typically provide that unit options begin vesting five years from the anniversary date of the applicable grant date. Shares issued as a result of unit option exercises are newly issued shares.

*Restricted Units*

A restricted unit is a common unit that participates in distributions and vests over a period of time yet during such time is subject to forfeiture. The compensation committee may make grants of restricted units to employees, directors and consultants containing such terms as the compensation committee determines. The compensation committee will determine the period over which restricted units granted to participants will vest. The compensation committee, in its discretion, may base its determination upon the achievement of specified financial objectives or other events. In addition, the restricted units will vest upon a change in control of the general partner of Inergy. If a grantee s employment, consulting arrangement or membership on the board of directors terminates for any reason, the grantee s restricted units will be automatically forfeited unless, and to the extent, the compensation committee or the terms of the award agreement provide otherwise.

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**Notes to Consolidated Financial Statements (Continued)**

The Company intends the restricted units to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of the common units. Therefore, plan participants will not pay any consideration for the common units they receive, and Inergy will receive no cash remuneration for the units.

Inergy granted 474,468, 299,983 and 326,910 restricted units during the years ended September 30, 2011, 2010 and 2009, respectively. Prior to the merger, Holdings granted 412,873 and 7,401 restricted units, reflective of the conversion to 0.77 Inergy common units, during the years ended September 30, 2010 and 2009, respectively. Some of the restricted units are 100% vested on the fifth anniversary of the grant date, subject to the provisions as outlined in the restricted unit award agreement. Some of the restricted units vest 25% after the third year, 25% after the fourth year and 50% after the fifth year. Some of these units are subject to the achievement of certain specified performance objectives and failure to meet the performance objectives will result in forfeiture and cancellation of the restricted units. The Company recognizes expense on these units each quarter by multiplying the closing price of the Company s common units on the date of grant by the number of units granted, and expensing that amount over the vesting period.

A summary of Inergy s weighted-average grant date fair value for restricted units for the year ended September 30, 2011, is as follows:

| | Weighted-Average Grant Date Fair Value | Number of Units |
|---|---|---|
| Non-vested at October 1, 2010 | $ 31.97 | 1,423,073 |
| Granted during the period ended September 30, 2011 | $ 39.02 | 474,468 |
| Vested during the period ended September 30, 2011 | $ 26.63 | 43,996 |
| Forfeited during the period ended September 30, 2011 | $ 33.01 | 71,150 |
| Non-vested at September 30, 2011 | $ 33.94 | 1,782,395 |

The weighted-average grant date fair value of restricted units granted and vested during the year ended September 30, 2010, amounted to $36.08 and $27.50, respectively. The weighted-average grant date fair value of restricted units granted and vested during the year ended September 30, 2009, amounted to $19.45 and $16.50, respectively. The fair value of restricted units vested during the years ended September 30, 2011, 2010 and 2009, was $1.5 million, $0.4 million and $2.0 million, respectively.

The compensation expense recorded by the Company related to these restricted stock awards was $5.7 million, $2.3 million and $1.6 million for the years ended September 30, 2011, 2010 and 2009, respectively.

*Unit Options*

Unit options issued under the long-term incentive plan have an exercise price equal to the fair market value of the units on the date of the grant. In general, unit options will expire after ten years and are subject to vesting periods as outlined in the unit option agreement. In addition, most unit option grants made under the plan provide that the unit options will become exercisable upon a change of control of the general partner or Inergy.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

A summary of Inergy s unit option activity for the years ended September 30, 2011, 2010 and 2009, is as follows:

| | Range of Exercise Prices | Weighted-Average Exercise Price | Number of Units |
|---|---|---|---|
| Outstanding at September 30, 2008 | $ 9.74 - $31.32 | $ 12.42 | 1,735,322 |
| Granted | | | |
| Exercised | $ 9.74 - $16.90 | $ 11.72 | 147,063 |
| Canceled | $ 9.74 - $31.31 | $ 13.35 | 64,483 |
| Outstanding at September 30, 2009 | $ 9.74 - $31.32 | $ 12.44 | 1,523,776 |
| Granted | | | |
| Exercised | $ 9.74 - $28.95 | $ 12.02 | 749,244 |
| Canceled | $ 9.74 - $30.96 | $ 13.85 | 25,790 |
| Outstanding at September 30, 2010 | $ 9.74 - $31.32 | $ 12.84 | 748,742 |
| Granted | | | |
| Exercised | $ 9.74 - $28.60 | $ 11.08 | 455,809 |
| Canceled | | | |
| Outstanding at September 30, 2011 | $ 9.74 - $31.32 | $ 15.59 | 292,933 |
| Exercisable at September 30, 2011 | $ 9.74 - $31.32 | $ 15.29 | 253,953 |

Information regarding options outstanding and exercisable as of September 30, 2011, is as follows:

| | Outstanding | | | Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Options Outstanding | Weighted-Average Remaining Contracted Life (years) | Weighted-Average Exercise Price | Options Exercisable | Weighted-Average Exercise Price |
| $9.74 - $31.32 | 292,933 | 4.3 | $ 15.59 | 253,953 | $ 15.29 |

The weighted-average remaining contract life for options outstanding and exercisable at September 30, 2011, was approximately four years. The fair value of each option grant was estimated as of the grant date using the Black-Scholes option pricing model using the assumptions outlined in the table below. Expected volatility was based on a combination of historical and implied volatilities of the Company s stock over a period at least as long as the options expected term. The expected life represents the period of time that the options granted are expected to be outstanding. The risk-free rate is based on the applicable U.S. Treasury yield curve in effect at the time of the grant of the share options.

The aggregate intrinsic values of options outstanding and exercisable at September 30, 2011, were $2.9 million and $2.7 million, respectively. The aggregate intrinsic value of unit options exercised during the year ended September 30, 2011, was $12.9 million. Aggregate intrinsic value represents the positive difference between the Company s closing stock price on the last trading day of the fiscal period, which was $25.02 on September 30, 2011, and the exercise price multiplied by the number of options outstanding.

As of September 30, 2011, there was $47.8 million of total unrecognized compensation cost related to unvested share-based compensation awards granted to employees under the restricted stock and unit option plans. That cost is expected to be recognized over a five-year period.

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

**Note 11. Employee Benefit Plans**

A 401(k) plan is available to all of Inergy s employees after meeting certain requirements. The plan permits employees to make contributions up to 75% of their salary, up to statutory limits, which was $16,500 in 2011. The plan provides for matching contributions by Inergy for employees completing one year of service of at least 1,000 hours. Aggregate matching contributions made by Inergy were $2.1 million, $2.3 million and $2.1 million in fiscal 2011, 2010 and 2009, respectively.

Of Inergy s 2,931 employees, 9% are subject to collective bargaining agreements. For the years ended September 30, 2011, 2010 and 2009, Inergy made contributions on behalf of its union employees to union sponsored defined benefit plans of $3.2 million, $2.8 million and $2.9 million, respectively.

**Note 12. Commitments and Contingencies**

Inergy periodically enters into agreements with suppliers to purchase fixed quantities of propane, distillates, natural gas and liquids at fixed prices. At September 30, 2011, the total of these firm purchase commitments was $336.2 million of which $331.1 million will occur over the course of the next twelve months with the balance of $5.1 million occurring over the following twelve months. The Company also enters into non-binding agreements with suppliers to purchase quantities of propane, distillates, natural gas and liquids at variable prices at future dates at the then prevailing market prices.

Inergy has entered into certain purchase commitments in connection with the identified growth projects primarily related to the North/South expansion project, the Watkins Glen NGL development project and the MARC I pipeline. The North/South expansion project consists of adding additional compression and measurement facilities to our existing Stagecoach Laterals, which when completed is expected to have firm transportation capacity of 325,000 dekatherms per day. The Watkins Glen NGL development project is expected to convert certain of the US Salt caverns into propane and butane storage with an initial capacity of 2.1 million barrels. The MARC I pipeline is a 40 mile, 30 bi-directional pipeline that will extend between our Stagecoach South Lateral interconnect with Tennessee Gas Pipeline Company s ( TGP ) 300 Line near its compressor station 319 and Transco s Leidy Line near its compressor station 517, and is expected to have a minimum of 550,000 dekatherms per day of firm transportation capacity. At September 30, 2011, the total of these firm purchase commitments was approximately $29.9 million and the majority of the purchases associated with these commitments are expected to occur over the course of the next twelve months.

Inergy is periodically involved in litigation proceedings. The results of litigation proceedings cannot be predicted with certainty; however, management believes that Inergy does not have material potential liability in connection with these proceedings that would have a significant financial impact on its consolidated financial condition, results of operations or cash flows.

Following the announcement of the Merger Agreement, two unitholder class action lawsuits were filed as described in Item 3 of form 10-K as filed with the Securities and Exchange Commission for the fiscal year ended September 30, 2010. The outcome of these lawsuits cannot be predicted with certainty; however, management believes that Inergy does not have material potential liability in connection with these proceedings that would have a significant financial impact on its consolidated financial condition, results of operations or cash flows.

Inergy utilizes third-party insurance subject to varying retention levels of self-insurance, which management considers prudent. Such self-insurance relates to losses and liabilities primarily associated with medical claims, workers compensation claims and general, product, vehicle and environmental liability. Losses are accrued based upon management s estimates of the aggregate liability for claims incurred using certain assumptions

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**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

followed in the insurance industry and based on past experience. The primary assumption utilized is actuarially determined loss development factors. The loss development factors are based primarily on historical data. Inergy s self insurance reserves could be affected if future claims development differs from the historical trends. Inergy believes changes in health care costs, trends in health care claims of its employee base, accident frequency and severity and other factors could materially affect the estimate for these liabilities. Inergy continually monitors changes in employee demographics, incident and claim type and evaluates its insurance accruals and adjusts its accruals based on its evaluation of these qualitative data points. At September 30, 2011 and 2010, Inergy s self-insurance reserves were $20.6 million and $19.3 million, respectively. The Company estimates that $14.1 million of this balance will be paid subsequent to September 30, 2012. As such, $14.1 million has been classified in other long-term liabilities on the consolidated balance sheets.

**Note 13. Segments**

Inergy s financial statements reflect two operating and reportable segments: propane operations and midstream operations. Inergy s propane operations include propane sales to end users, the sale of propane-related appliances and service work for propane-related equipment, the sale of distillate products and wholesale distribution of propane and marketing and price risk management services to other users, retailers and resellers of propane. Inergy s midstream operations include storage of natural gas and natural gas liquids for third parties, fractionation of natural gas liquids, processing of natural gas, distribution of natural gas liquids and the production and sale of salt. Results of operations for Schenck and Pennington are included in the propane segment, while results of operations for Tres Palacios and Seneca Lake are included in the midstream segment.

The identifiable assets associated with each reportable segment include accounts receivable and inventories. Goodwill, property, plant and equipment and expenditures for property, plant and equipment are also presented for each segment. The net asset/liability from price risk management, as reported in the accompanying consolidated balance sheets, is primarily related to the propane segment.

Revenues, gross profit, identifiable assets, goodwill, property, plant and equipment and expenditures for property, plant and equipment for each of Inergy s reportable segments are presented below (*in millions*):

| | Year Ended September 30, 2011 | | | | |
|---|---|---|---|---|---|
| | Propane Operations | Midstream Operations | Intersegment Operations | Corporate Assets | Total |
| Retail propane revenues | $ 858.6 | $ | $ | $ | $ 858.6 |
| Wholesale propane revenues | 562.6 | 40.9 | (0.2) | | 603.3 |
| Storage, fractionation and other midstream revenues | | 468.0 | (5.5) | | 462.5 |
| Transportation revenues | 19.9 | 17.2 | | | 37.1 |
| Propane-related appliance sales revenues | 19.6 | | | | 19.6 |
| Retail service revenues | 16.4 | | | | 16.4 |
| Rental service and other revenues | 28.1 | | | | 28.1 |
| Distillate revenues | 128.2 | | | | 128.2 |
| Gross profit | 493.2 | 184.6 | | | 677.8 |
| Identifiable assets | 289.9 | 90.7 | | | 380.6 |
| Goodwill | 336.1 | 141.8 | | 20.2 | 498.1 |
| Property, plant and equipment | 774.4 | 1,830.7 | | 12.3 | 2,617.4 |
| Additions to property, plant and equipment | 16.0 | 183.3 | | 0.9 | 200.2 |

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

| | Year Ended September 30, 2010 | | | | |
|---|---|---|---|---|---|
| | Propane Operations | Midstream Operations | Intersegment Operations | Corporate Assets | Total |
| Retail propane revenues | $ 796.5 | $ | $ | $ | $ 796.5 |
| Wholesale propane revenues | 449.3 | 26.8 | (0.2) | | 475.9 |
| Storage, fractionation and other midstream revenues | | 302.9 | (1.2) | | 301.7 |
| Transportation revenues | 17.9 | 17.4 | | | 35.3 |
| Propane-related appliance sales revenues | 22.2 | | | | 22.2 |
| Retail service revenues | 16.9 | | | | 16.9 |
| Rental service and other revenues | 26.6 | | | | 26.6 |
| Distillate revenues | 110.9 | | | | 110.9 |
| Gross profit | 490.1 | 131.2 | (1.2) | | 620.1 |
| Identifiable assets | 184.2 | 60.9 | | | 245.1 |
| Goodwill | 327.7 | 96.4 | | 20.2 | 444.3 |
| Property, plant and equipment | 767.2 | 916.0 | | 12.0 | 1,695.2 |
| Additions to property, plant and equipment | 14.7 | 69.1 | | 1.6 | 85.4 |

| | Year Ended September 30, 2009 | | | | |
|---|---|---|---|---|---|
| | Propane Operations | Midstream Operations | Intersegment Operations | Corporate Assets | Total |
| Retail propane revenues | $ 736.7 | $ | $ | $ | $ 736.7 |
| Wholesale propane revenues | 368.2 | 19.7 | (0.2) | | 387.7 |
| Storage, fractionation and other midstream revenues | | 220.8 | (0.7) | | 220.1 |
| Transportation revenues | 16.8 | 16.9 | | | 33.7 |
| Propane-related appliance sales revenues | 21.4 | | | | 21.4 |
| Retail service revenues | 17.8 | | | | 17.8 |
| Rental service and other revenues | 27.5 | | | | 27.5 |
| Distillate revenues | 125.7 | | | | 125.7 |
| Gross profit | 471.0 | 103.4 | (0.7) | | 573.7 |
| Identifiable assets | 139.6 | 51.6 | | | 191.2 |
| Goodwill | 277.9 | 96.4 | | 20.2 | 394.5 |
| Property, plant and equipment | 697.0 | 847.1 | | 11.1 | 1,555.2 |
| Additions to property, plant and equipment | 14.0 | 203.7 | | 0.9 | 218.6 |

**Inergy, L.P. and Subsidiaries**

**Notes to Consolidated Financial Statements (Continued)**

### Note 14. Quarterly Financial Data (Unaudited)

Inergy s business is seasonal due to weather conditions in its service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to industrial and agricultural customers are much less weather sensitive. Summarized unaudited quarterly financial data is presented below (*in millions, except per unit information*):

| | Quarter Ended | | | |
|---|---|---|---|---|
| | December 31 | March 31 | June 30 | September 30 |
| **Fiscal 2011** | | | | |
| Revenues | $ 596.0 | $ 720.5 | $ 388.7 | $ 448.6 |
| Operating income (loss) | 71.7 | 113.4 | (8.9) | (21.7) |
| Net income (loss) | 38.5 | 36.6 | (35.5) | (50.2) |
| Net income (loss) attributable to partners | 66.7 | 36.6 | (35.5) | (50.2) |
| Net income (loss) per limited partner unit:[a] | | | | |
| Basic | $ 0.82 | $ 0.33 | $ (0.32) | $ (0.42) |
| Diluted | $ 0.72 | $ 0.30 | $ (0.32) | $ (0.42) |
| **Fiscal 2010** | | | | |
| Revenues | $ 501.7 | $ 691.1 | $ 291.6 | $ 301.6 |
| Operating income (loss) | 67.4 | 110.7 | (13.4) | (28.6) |
| Net income (loss) | 45.8 | 87.2 | (35.1) | (51.5) |
| Net income attributable to partners | 16.5 | 21.3 | 12.4 | 11.6 |
| Net income per limited partner unit:[a],[b] | | | | |
| Basic | $ 0.47 | $ 0.60 | $ 0.34 | $ 0.32 |
| Diluted | $ 0.35 | $ 0.44 | $ 0.26 | $ 0.24 |

(a) The accumulation of basic and diluted net income (loss) per limited partner unit does not total the amount for the fiscal year due to changes in ownership percentages throughout the year.

(b) These amounts have been adjusted for the conversion of Inergy Holdings common units into 0.77 Inergy common units, which occurred on November 5, 2010.

### Note 15. Subsequent Events

The Company has identified subsequent events requiring disclosure through the date of the filing of this Form 10-K.

On November 14, 2011, a quarterly distribution of $0.705 per limited partner unit was paid to unitholders of record on November 7, 2011, with respect to the fourth fiscal quarter of 2011, which totaled $83.9 million.

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## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

**INERGY, L.P.**

By Inergy GP, LLC
(its general partner)

Dated: November 15, 2011 By /s/ JOHN J. SHERMAN
**John J. Sherman, President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following officers and directors of Inergy GP, LLC, as general partner of Inergy, L.P., the registrant, in the capacities and on the dates indicated.

| Date | Signature and Title |
|---|---|
| November 15, 2011 | /s/ JOHN J. SHERMAN<br>**John J. Sherman,**<br>**President, Chief Executive Officer and Director**<br>**(Principal Executive Officer)** |
| November 15, 2011 | /s/ R. BROOKS SHERMAN, JR.<br>**R. Brooks Sherman, Jr.,**<br>**Executive Vice President and Chief Financial Officer**<br>**(Principal Financial Officer and Principal Accounting Officer)** |
| November 15, 2011 | /s/ PHILLIP L. ELBERT<br>**Phillip L. Elbert,**<br>**President and Chief Operating Officer** |
| November 15, 2011 | /s/ WARREN H. GFELLER<br>**Warren H. Gfeller, Director** |
| November 15, 2011 | /s/ ARTHUR B. KRAUSE<br>**Arthur B. Krause, Director** |
| November 15, 2011 | /s/ ROBERT D. TAYLOR<br>**Robert D. Taylor, Director** |
| November 15, 2011 | /s/ RICHARD T. O BRIEN |

**Richard T. O Brien, Director**

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**Schedule II**

**Inergy, L.P. and Subsidiaries**

**Valuation and Qualifying Accounts**

*(in millions)*

| Year Ended September 30, | Balance at beginning of period | Charged to costs and expenses | Other Additions | Deductions (write-offs) | Balance at end of period |
|---|---|---|---|---|---|
| Allowance for doubtful accounts | | | | | |
| 2011 | $ 3.2 | $ 3.7 | $ 0.9 | $ (5.2) | $ 2.6 |
| 2010 | 2.7 | 2.8 | 0.8 | (3.1) | 3.2 |
| 2009 | 6.4 | 3.7 | 0.3 | (7.7) | 2.7 |